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Comments attached.

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Comparison of Analysis of Natural Gas Export Impacts from Studies Done by NERA Economic Consultants and Purdue University

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Executive Summary

The U.S. Department of Energy (DOE) is soon to make decisions on the extent to which natural gas exports will be approved. With the shale gas boom, the US is expected to have very large natural gas resources, so the key question is would it be better to rely completely on free market resource allocations which would lead to large exports of natural gas or to limit natural gas exports so that more could be used in the US. There are two economic studies of the impacts on the U.S. economy of increased natural gas exports – one done for DOE by NERA Economic Consultants and the other by Tyner and Sarica of Purdue University. The NERA study results in a very small income gain for the U.S. from increased natural gas exports, and the Purdue study results in a small economic loss.

Any time trade policy questions are raised, it is often not so much about net gains as about winners and losers. Net gains or losses, whichever may be the case are tiny. The $10 billion gain in the NERA study amounts to 6 hours of U.S. economic activity. In the NERA analysis, the losses are in wage and capital income in energy intensive industries, and the gains are almost exclusively wealth transfers to owners of natural gas resources. Perhaps a more important question is should the nation accept the economic losses in many key economic sectors to provide wealth transfers to natural gas resource owners? In addition, while U.S. industry and consumers would face higher natural gas and electricity prices, foreign competitors would face lower energy costs with increased U.S. natural gas exports.

Beyond the economic and income distribution issues, there are also associated environmental impacts not covered in the NERA study. In the Purdue study, U.S. GHG emissions increase when there are increased natural gas exports. An argument could be made that GHG emissions might fall in other regions as they replace coal or other fossil fuels with cleaner natural gas. However, there likely would be a sort of emissions transactions cost in liquefying, transport, and de-liquefying the gas that would result still in a net GHG increase. In addition, because less natural gas would be used in local fleets because of natural gas exports, there would be an increase in local particulate emissions due to relatively more use of diesel and less use of CNG.

The bottom line is that there are very important issues concerning whether or to what extent there really are any economic gains to the U.S. from exporting natural gas instead of using it domestically. There are income distribution consequences of natural gas export impacts that need to be factored into the export permit decisions, and there are environmental impacts that should be counted as well. The results of these two studies, while showing some similarities are different enough in final outcomes to warrant much more informed debate on this critically important national policy issue.

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The U.S. Department of Energy (DOE) is soon to make decisions on the extent to which natural gas exports will be approved. With the shale gas boom, the US is expected to have very large natural gas resources, so the key question is would it be better to rely completely on free market resource allocations which would lead to large exports of natural gas or to limit natural gas exports so that more could be used in the US. Exports would be economically attractive because there is a very large price gap at present between US natural gas price (around $3.50/MCF) and prices in foreign markets, which can range up to $15/MCF. On the other side, there is potentially large domestic demand for natural gas in electricity generation, industrial applications, the transportation sector, and for other uses. There is no doubt that exporting a large amount of natural gas would increase the domestic natural gas price for all these potential uses. Higher natural gas prices would, in turn, mean higher electricity prices, so the higher energy costs would go beyond just natural gas users. These higher energy costs would also lead to contraction in energy intensive sectors relative to the reference case with small natural gas exports.

NERA Economic Consulting study

In December 2012, DOE released a commissioned study done by NERA Economic Consultants, a private consulting firm[1]. They used their own proprietary energy-economy model named NewERA for the analysis. Their results suggest that the US achieves economic gains from natural gas exports and that the gains increase as the level of natural gas exports grows. Their result is the classical economic result that free trade provides net gains to the economy under most conditions. While economic theory does not suggest that free trade always produces economic gains for all parties under all conditions, the general argument is that under a wide range of conditions, free trade does provide net benefits with some winners and some losers. The NERA results do show higher natural gas prices due to exports with the magnitude of the increase depending on domestic and global supply and demand factors. The NERA study used input data and information from a companion study done by the Energy information Agency in DOE [2], which estimated the impacts of export levels on US natural gas prices.

The NERA analysis focused on export levels of 6 and 12 BCF per day, but there were many other scenarios and sensitivity analyses. In general, the welfare or net income increases estimated in the NERA scenarios were very small, generally ranging from 0.01 to 0.025 percent over the reference case. There were considerable losses in capital and wage income in sectors affected by the higher natural gas prices, and

income gains to natural gas resource owners through export earnings and wealth transfers to resource owners. By 2030 the total net increase in GDP amounted to about $10 billion 2010$, which could be perceived as being quite small in a $15 trillion economy [3]. Wage income falls in agriculture, energy intensive sectors, and the electricity sector. The percentage declines in wages in these sectors were generally much greater than the percentage increases in net national income. Natural gas price increases did not exceed 20 percent in any of the simulations. The NewERA energy-economy model takes inputs from the EIA NEMS natural gas projections [2] and from a global natural gas model.

Purdue MARKAL-Macro Analysis

The Purdue approach was to use a well-established bottom-up energy model named MARKAL (MARKet ALlocation). Bottom-up means that the model is built upon thousands of current and future prospective energy technologies and resources. These energy resources supply projected energy service demands for the various sectors of the economy. In addition to the standard MARKAL model, we also have adapted a version of the MARKAL-Macro model which permits us to include feedbacks between energy prices and economic activity. Thus the GDP effects of alternative energy policies are captured as well as technology and supply impacts. For these reasons, MARKAL-Macro is an ideal tool for this kind of analysis. The Purdue analysis was done for the two levels from the EIA and NERA reports (6 BCF/day and 12 BCF/day plus 18 BCF per day). The EIA NEMS model is a bottom-up model somewhat similar to MARKAL. Details of the analysis are available in Sarica and Tyner [4].

The Purdue analysis shows that increasing natural gas exports actually results in a slight decline in GDP. Essentially the gains from exports are less than the losses in electricity and energy intensive sectors in the economy. The GDP losses are around 0.04%, 0.11%, and 0.17% for the 6, 12, and 18 BCF/day cases respectively for the year 2035.

The general trends in the change in energy resource mix for 2035 are as follows: 1)the domestic energy share for natural gas falls from 25 to 22 percent) as exports of natural gas increase; 2)domestic use of coal increases from 21 to 23 percent as natural gas exports increase; 3)the fraction of oil in total consumption increases from 36 to 37 percent; 4)there are small increases in nuclear and renewables (hydro, solar, wind, and biomass).

The impacts on the electricity sector come in higher electricity prices and higher GHG emissions. In 2035, electricity price is up compared with the reference case by 1.1%, 4.3%, and 7.2% for the 6 BCF, 12 BCF, and 18 BCF cases respectively. Of course, these higher electricity prices are passed through the entire economy through industrial, commercial, and residential sectors. Electricity GHG emissions in the early years of the simulation horizon are around 2% higher for the 6 BCF case, and 7-12% higher for the 12 and 18 BCF cases.

In 2035, CNG use in transportation for the reference case is 1.3 bil. gal. gasoline equivalent, but it drops to 0.2-0.3 in the three export cases. CNG use in heavy duty vehicles disappears in the 12 BCF case, and CNG use in most of the vehicle categories drops considerably. The bottom line is that while CNG use in transport is not large even in the reference case, it plummets in the export cases.

We examined impacts on the metals, non-metals, paper, and chemical sectors. Total energy use and thus also economic output declines from 1 to 4 percent in all the energy intensive sectors depending on the sector and the level of natural gas exports. Thus, it is easy to see how the Purdue results show a decline in GDP since there are declines in several key sectors in the economy driven by the higher natural gas prices.

Comparison

These studies use different models, somewhat different data sets, and different modeling parameters. The results are different, but there are some important similarities. On GDP impacts, the sign of the change is different. NERA gets a very small but positive welfare impact, and Purdue MARKAL-Macro gets a small negative impact. Our view is that because the net income impacts are so small, it is not appropriate to place much emphasis on that outcome. What is important is to explain the differences and to understand the drivers of the differences.

Purdue MARKAL-Macro gets larger natural gas price increases, which, in-turn leads to electricity price increases and to declines in energy use and output for key energy intensive sectors. The decline in economic activity of these sectors is a key driver in the decline in GDP. In fact, since neither the Purdue nor the NERA model are complete global CGE models, the estimated decline in economic activity of these sectors is probably an underestimate because all these sectors would face higher costs and would be less competitive on the global market with higher natural gas exports. In other words, U.S, economic losses likely would be larger than estimated by either model. Also, other nations would face lower energy costs with our LNG exports.

Any time trade policy questions are raised, it is often not so much about net gains as about winners and losers. Net gains or losses, whichever may be the case are tiny. The $10 billion gain in the NERA study amounts to 6 hours of U.S. economic activity. In the NERA analysis, the losses are in wage and capital income in energy intensive industries, and the gains are almost exclusively wealth transfers to owners of natural gas resources. Perhaps a more important question is should the nation accept the economic losses in many key economic sectors to provide wealth transfers to natural gas resource owners?

In addition to the economic and income distribution issues, there are also associated environmental impacts not covered in the NERA study. In the Purdue study, U.S. GHG emissions increase when there are increased natural gas exports. An argument could be made that GHG emissions might fall in other regions as they replace coal or other fossil fuels with cleaner natural gas. However, there likely would be a sort

of emissions transactions cost in liquefying, transport, and de-liquefying the gas that would result still in a net GHG increase. In addition, because less natural gas would be used in local fleets because of natural gas exports, there would be an increase in local particulate emissions due to relatively more use of diesel and less use of CNG.

Conclusions

Beyond the analysis conducted here, it is important to note that neither the model used in this analysis nor the NERA model are global in scope. Thus, neither includes the trade impacts of US natural gas exports. However, we can describe those impacts qualitatively. Increased US natural gas exports will reduce energy costs for industry and consumers in foreign countries and increase those costs for the US. Thus, US industry will be rendered less competitive compared with foreign industry. This loss of export revenue would be in addition to the GDP loss estimated in this analysis. Moreover, US consumers lose due to higher energy prices, and foreign consumers gain.

Given all the results of this analysis, it is clear that policy makers need to be very careful in approving US natural gas exports. While we are normally disciples of the free trade orthodoxy, one must examine the evidence in each case. We have done that, and the analysis shows that this case is different. Using the natural gas in the US is more advantageous than exports, both economically and environmentally.

The bottom line is that there are very important issues concerning whether or to what extent there really are any economic gains to the U.S. from exporting natural gas instead of using it domestically. There are income distribution consequences of natural gas export impacts that need to be factored into the export permit decisions, and there are environmental impacts that should be counted as well. The results of these two studies, while showing some similarities are different enough in final outcomes to warrant much more research and informed debate on this critically important national policy issue.

References

1. NERA Economic Consulting. Macroeconomic Impacts of LNG Exports from the United States. Washington, D.C.: 2012 2012. Report No.
2. Energy Information Administration. Effect of Increased Natural Gas Exports on Domestic Energy Markets. Washington, D.C.January 2012.
3. Trading Economics. 2012. Available from: http://www.tradingeconomics.com/united-states/gdp.
4. Sarica K, Tyner WE. Economic and Environmental Impacts of Increased US Exports of Natural Gas. Energy Policy. 2013;under review.

MAGNOLIA LNG PROJECT

Resource Report 9

AIR QUALITY AND NOISE

Docket No: CP14-____-000
30 April 2014

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SUMMARY OF FILING INFORMATION

INFORMATION	SECTION REFERENCE
Minimum Requirements to Avoid Rejection	
☑ 1. Describe existing air quality in the vicinity of the project. (§ 380.12(k)(1)) • Identify criteria pollutants that may be emitted above EPA-identified significance levels.	Section 9.2.3
☑ 2. Quantify the existing noise levels (day-night sound level (Ldn) and other applicable noise parameters) at noise sensitive areas and at other areas covered by relevant state and local noise ordinances. (§ 380.12(k)(2)) • If new compressor station sites are proposed, measure or estimate the existing ambient sound environment based on current land uses and activities. • For existing compressor stations (operated at full load), include the results of a sound level survey at the site property line and nearby noise-sensitive areas. • Include a plot plan that identifies the locations and duration of noise measurements. • All surveys must identify the time of day, weather conditions, wind speed and direction, engine load, and other noise sources present during each measurement.	Section 9.3.2
☑ 3. Quantify existing and proposed emissions of compressor equipment, plus construction emissions, including nitrogen oxides (NOx) and carbon monoxide (CO), and the basis for these calculations. Summarize anticipated air quality impacts for the project. (§ 380.12(k)(3)) • Provide the emission rate of NOx from existing and proposed facilities, expressed in pounds per hour and tons per year for maximum operating conditions, include supporting calculations, emission factors, fuel consumption rate, and annual hours of operation.	Construction Emissions: Section 9.2.5.2 Operation Emissions: Section 9.2.6.1 Impacts: Section 9.2.6.2

SUMMARY OF FILING INFORMATION

INFORMATION	SECTION REFERENCE
☑ 4. Describe the existing compressor units at each station where new, additional, or modified compressor units are proposed, including the manufacturer, model number, and horsepower of the compressor units. For proposed new, additional, or modified compressor units include the horsepower, type, and energy source. (§ 380.12(k)(4))	There are no compressor stations included as part of the proposed Project; however, one will be required as part of the transportation of feed gas to the Magnolia LNG Project as explained in Resource Report 1, Section 1.13.
☑ 5. Identify any nearby noise-sensitive area by distance and direction from the proposed compressor unit building/enclosure. (§ 380.12(k)(4))	Section 9.3.2 and Table 9.3-1
☑ 6. Identify any applicable state or local noise regulations. (§ 380.12(k)(4)) • Specify how the facility will meet the regulations.	Section 9.3.1, Section 9.3.3.2, Table 9.3-9, and Section 9.3.4.2
☑ 7. Calculate the noise impact at noise-sensitive areas of the proposed compressor unit modifications or additions, specifying how the impact was calculated, including manufacturer's data and proposed noise control equipment. (§ 380.12(k)(4))	Section 9.3.3.2, Table 9.3-9, and Section 9.3.4.2
Additional Information Often Missing and Resulting in Data Requests	
☑ Provide copies of application for state air permits and agency determinations, as appropriate.	Appendix 9.E *[pending LDEQ review]*
☑ For major sources of air emissions (as defined by the EPA), provide copies of applications for permits to construct (and operate, if applicable) or for applicability determinations under regulations for the prevention of significant air quality deterioration and subsequent determinations.	Appendix 9.D *[pending LDEQ review]*
☑ Describe measures and manufacturer's specifications for equipment proposed to mitigate impact to air and noise quality, including emission control systems, installation of filters, mufflers, or insulation of piping and building, and orientation of equipment away from noise-sensitive areas.	Sections 9.1.1, 9.2.6, and 9.3.3.2 and Table 9.3-8

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Appendix 9.A: Construction Emissions

Appendix 9.B: Operational Emissions

9.B.1 Operational Emissions Calculations
9.B.2 Fugitive Emissions Calculations *[PRIVILEGED]*

Appendix 9.C: Air Modeling Protocols and Associated Correspondence

9.C.1 Air Quality Modeling Protocol
9.C.2 Marine and Stationary Sources Air Quality Modeling Protocol
9.C.3 Modeling Protocol - Ozone Impact Analysis of the Proposed Magnolia LNG Project

Appendix 9.D: Noise Study

Appendix 9.E: Air Permit Application *[Pending LDEQ Review]*

ACRONYMS AND ABBREVIATIONS

BOG	boil-off gas
BTEX	benzene, toluene, ethylbenzene, and xylene
BTU	British thermal unit
CAA	Clean Air Act
CFR	Code of Federal Regulations
CHP	combined heat and power
CO	carbon monoxide
CO_2e	carbon dioxide equivalent
Commission	Federal Energy Regulatory Commission; also the FERC
dB	decibel(s)
dBA	A-weighted decibel(s)
ECA	Emission Control Area
FERC	Federal Energy Regulatory Commission; also the Commission
GHG	greenhouse gas
H_2S	hydrogen sulfide
HAP	hazardous air pollutant
HHV	higher heating value
HP	high pressure
Hz	Hertz
IMO	International Maritime Organization
km	kilometer(s)
KMLP	Kinder Morgan Louisiana Pipeline
kW	kilowatt(s)
LAC	Louisiana Administrative Code
LDEQ	Louisiana Department of Environmental Quality
Ldn	Day-Night Average Sound Level
LDWF	Louisiana Department of Wildlife and Fisheries
L_{eq}	Equivalent Sound Level
L_{max}	the maximum instantaneous noise level during a specific period of time

m^3	cubic meters
Magnolia	Magnolia LNG, LLC
MARPOL	International Convention for the Prevention of Pollution from Ships
MMBtu	million British thermal units
MOVES	Motor Vehicle Emission Simulator
MR	mixed refrigerant
mtpa	million (metric) tonnes per annum
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NNSR	nonattainment new source review
NO_2	nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration
NRDA	Natural Resources Damage Assessment
NSA	noise sensitive area
NSPS	New Source Performance Standards
NSR	New Source Review
O_3	ozone
OSMR®	Optimized Single Mixed Refrigerant
Pb	lead
PM_{10}	particulate matter 10 microns or less in diameter
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
Port District	Lake Charles Harbor & Terminal District
ppb	parts per billion
ppm	part(s) per million
ppmw	parts per million by weight
Project	Magnolia LNG Project
PSD	Prevention of Significant Deterioration
PTE	potential to emit
RICE	Reciprocating Internal Combustion Engine
RR	Resource Report

SIL	significant impact level
SIP	State Implementation Plan
SLAMS	State and Local Air Monitoring Station
SMR	single mixed refrigerant
SO_2	sulfur dioxide
SPL	sound pressure level
TAP	toxic air pollutant
tpy	tons per year
Trunkline LNG	Trunkline LNG LLC
Trunkline LNG project	Trunkline LNG, LLC, Lake Charles Export Terminal
U.S.C.	United States Code
USEPA	U.S. Environmental Protection Agency
VdB	vibration velocity level in decibels
VOC	volatile organic compound

9 AIR QUALITY AND NOISE

Magnolia LNG, LLC (Magnolia) has prepared this Resource Report (RR) 9 in compliance with the requirements of the Federal Energy Regulatory Commission (FERC or the Commission) regulations for authorization under Section 3(a) of the Natural Gas Act to site, construct and operate facilities necessary to liquefy natural gas at a proposed site in Lake Charles, Louisiana. On March 12, 2013, Magnolia requested approval to participate in the FERC Pre-Filing Process to assist in the identification and proper assessment of issues and to provide input into the development of the environmental resource reports. The FERC granted this request on March 20, 2013, and assigned Pre-Filing (PF) Docket Number PF13-9-000.

This RR 9 describes existing air quality and noise conditions that will be directly or indirectly affected by construction and operation of the proposed Magnolia LNG Project (referred to herein as the Project). It characterizes and quantifies existing air quality and noise; identifies affected noise-sensitive areas; and includes discussions of potential impacts on air quality and noise from construction activities and operation of the proposed facilities. RR 9 also summarizes federal, state, municipal, and other local agency air quality and noise regulations applicable to the proposed Project and, as appropriate, discusses forms of mitigation that will be used to reduce impacts during construction and operation of the facilities associated with the Project. Information contained in this RR was obtained from equipment vendor data sheets, desktop analysis, and review of available literature.

9.1 PROJECT DESCRIPTION

9.1.1 Proposed Facilities

Magnolia is proposing to develop a liquefied natural gas (LNG) facility capable of producing a nominal capacity of approximately 8.0 million (metric) tonnes per annum (mtpa) of LNG using its highly efficient and patented Optimized Single Mixed Refrigerant (OSMR®) technology. The Project would receive natural gas via a tie-in to an existing interstate pipeline that traverses the proposed Project site (refer to Section 9.1.6 below for additional information). For additional information concerning the Project Description, please refer to RR 1, “General Project Description.”

The natural gas would be treated, liquefied, and stored on-site in two full containment LNG storage tanks with a net pumpable capacity of approximately 160,000 cubic meters (m^3) of LNG each. At full plant capacity, the Project would consist of four LNG trains each with a nominal capacity of 2.0 mtpa of LNG (total nominal capacity of approximately 8.0 mtpa). The LNG would be loaded onto LNG carriers for export overseas; LNG carriers and barges for domestic marine distribution and the possibility of LNG bunkering; and LNG trucks for road distribution to LNG refueling stations in Louisiana and the surrounding states. The Project site is well-positioned to provide access for loading of LNG carriers and also for potential LNG barges and LNG trucks.

Approximately 1.4 billion standard cubic feet per day of natural gas would be contracted to support Project operations. Each LNG train has a guaranteed capacity of 1.7 mtpa of LNG,

and a nominal capacity of 2.0 mtpa of LNG. A key aspect of the Magnolia LNG Project is the use of the patented and highly efficient OSMR® liquefaction process. This process utilizes existing and proven technologies in an innovative way to achieve better performance. In particular, the design incorporates the use of a combined heat and power (CHP) system, and an Ammonia Auxiliary Refrigeration Plant.

The CHP technology is employed to recover the waste heat from the gas turbines within each LNG train. The recovered waste heat produces high pressure (HP) steam via once through steam generators mounted on the gas turbine exhausts. The produced HP steam is used to power steam turbines that drive the ammonia compressors within the LNG train, plus other process steam users. These ammonia compressors drive the Ammonia Auxiliary Refrigeration Plant.

The Ammonia Auxiliary Refrigeration Plant, driven from recovered free waste heat, provides additional cooling in three locations within the OSMR® liquefaction process. Firstly, the ammonia refrigerant is applied to cooling the wet gas exiting the amine contactor. Secondly, it is applied to cooling the inlet air of each gas turbine which increases the output of the gas turbine while improving stability. Lastly, it is used to pre-cool the mixed refrigerant (MR) prior to entering the cold box. These applications of these features result in an efficiency improvement of approximately 30 percent which translates into approximately 30 percent less air pollutant emissions per unit of LNG produced.

9.1.2 Location of Proposed Facilities

The Project would be located on the south shore of the Industrial Canal on the Port of Lake Charles Tract 475, an approximately 115-acre parcel of land in Calcasieu Parish, south of Lake Charles, Louisiana. The Industrial Canal is located off the main Calcasieu River Ship Channel. The Project would be located in an area zoned for heavy industrial use and would be consistent with other industrial facilities along the shoreline. The coordinates of the proposed Project site are as follows: Latitude: 30° 06′ 20.30″ N; Longitude: 93° 17′ 54.00″ W. Figure 9.1-1 is a general location map of the Project.

9.1.3 Project Site Lease Agreements

On March 6, 2013, Magnolia signed an exclusive and binding four-year Real Estate Lease Option Agreement with the Lake Charles Harbor & Terminal District (Port District) for approximately 107.59 acres of the approximately 115-acre Project site (see Port District Option Agreement, in Appendix 1.C.1 of RR 1). The Port District Option Agreement includes a clause for a 30-year-term ground lease option with the right to extend the lease term for four periods of 10 years each for a total of 70 years. Subject to compliance with the terms of the Port District Option Agreement, Magnolia may exercise the option and enter into the ground lease with the Port District at any time.

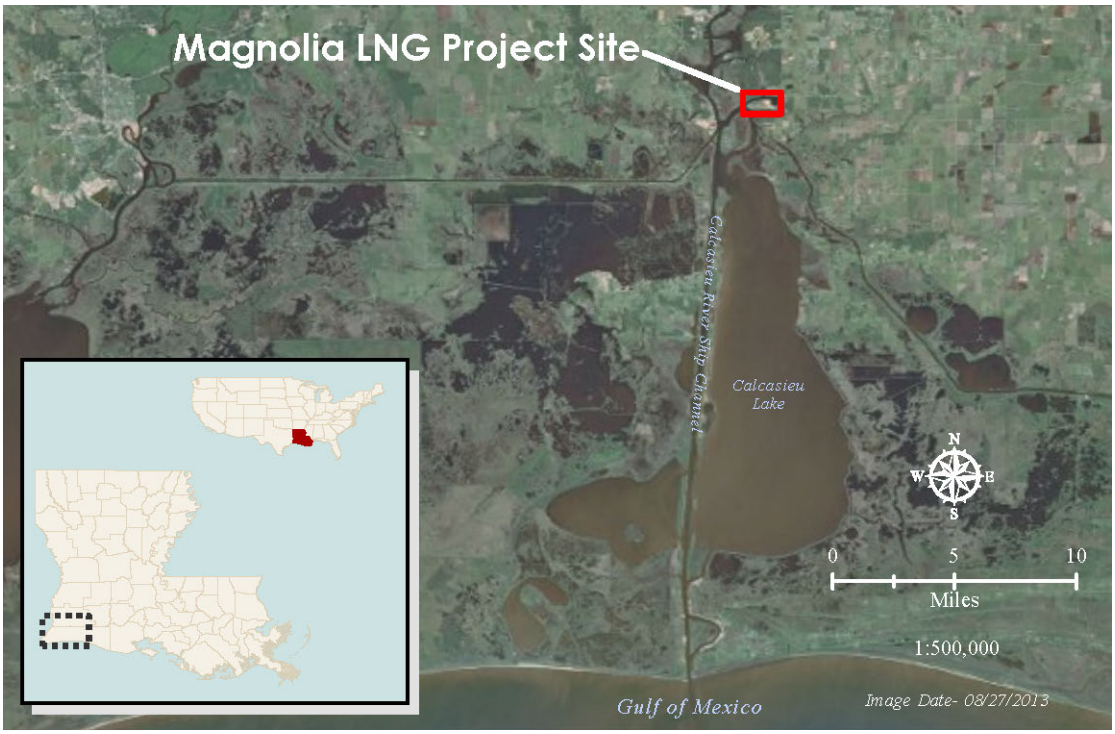


Figure 9.1-1 General Location Map of the Magnolia LNG Project

On September 26, 2013, Magnolia signed an exclusive and binding four-year Real Estate Lease Option Agreement with BG LNG Services, LLC, for approximately 5.74 acres of the approximately 115-acre Project site (see Appendix 1.C.2 in RR 1). On October 21, 2013, Magnolia signed the First Amendment to the Port District Option Agreement (see Appendix 1.C.3 in RR 1) for an additional area of approximately 1.99 acres. These two agreements are on similar terms and conditions as the initial Port District Option Agreement.

Through the combination of the Port District Option Agreement, the BG LNG Option Agreement, and the First Amendment to the Port District Option Agreement, Magnolia will have control of the entire area comprising the approximately 115-acre Project site for at least the minimum expected operational life of the Project, which is 30 years, with the right to extend the lease term. Figure 9.1-2 shows the boundary of the total leased area.

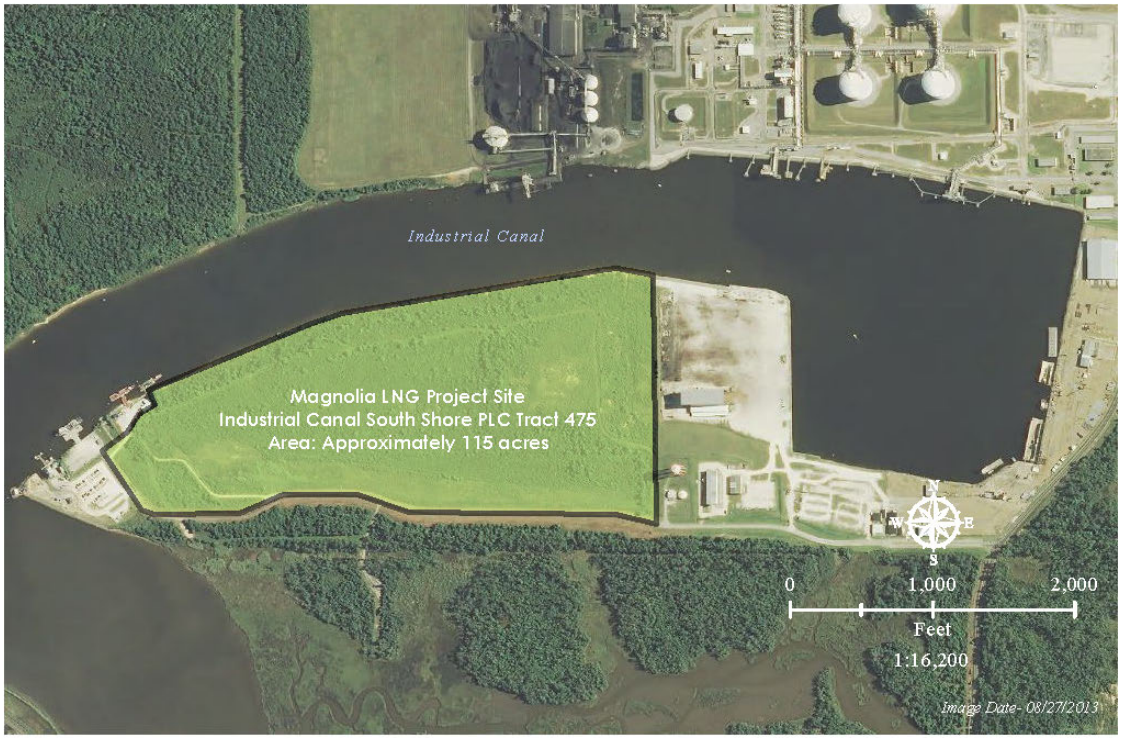


Figure 9.1-2 Project Site Boundary Map

9.1.4 LNG Vessel Loading

LNG carriers would access the Magnolia site by proceeding inbound from the Gulf of Mexico, into the Calcasieu River Ship Channel, traveling northbound to the "Devil's Elbow" intersection, and then turning right (easterly) into the Calcasieu River Industrial Canal and proceeding another 2 miles northeast to the Industrial Canal turning basin and subsequently mooring at the Magnolia LNG facility on the south side of the Industrial Canal. The total inbound transit from the entrance to the Calcasieu River jetties at the Gulf of Mexico to the Project site is approximately 25.5 statute miles. The route is reversed for outbound LNG carrier transits.

To accommodate LNG vessels and to minimize interference with existing canal traffic, the LNG vessel loading facility is planned to be recessed into the northern boundary of the site (see Figure 9.1-3). The following components are included as part of the LNG vessel loading platform: main incoming cryogenic loading line of nominal 30-inch size (outside diameter of 32 inches; pipe schedule 10S, with a wall thickness of 0.31 inches) from the LNG storage tank, three 16-inch LNG loading arms, one 16-inch vapor return arm, one 8-inch LNG loading arm with piggyback 6-inch vapor return line for loading LNG barges, electro-hydraulic control system, hydraulic quick connect/disconnect system, hydraulic emergency release system, swivel

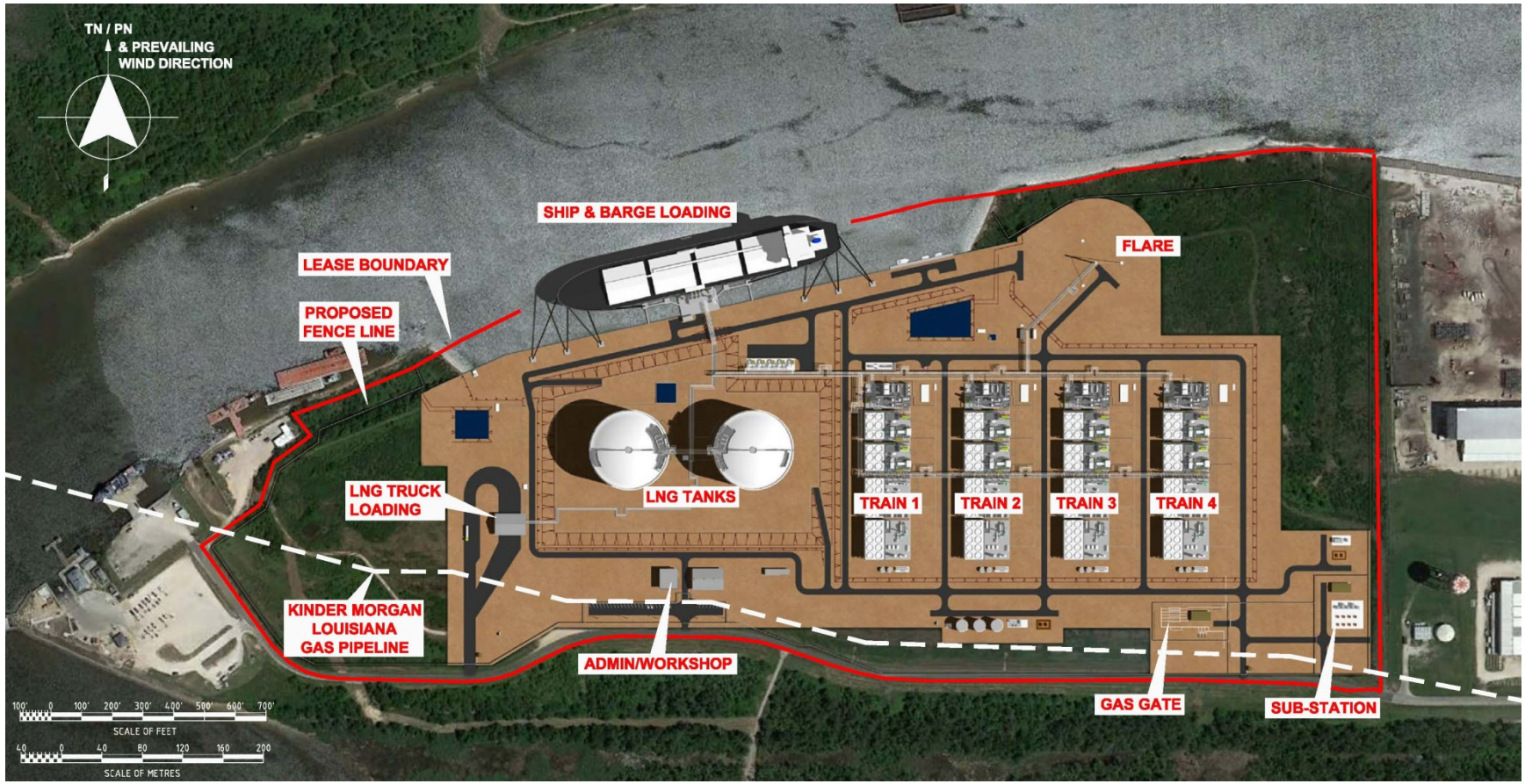


Figure 9.1-3 Artist's Rendering of Proposed Facility Layout

joints with nitrogen gas purge; mechanical locking devices, drain connections, and berthing dolphins, mooring dolphins, tug mooring, and walkways. For additional information on the Magnolia LNG marine facilities, refer to RR 1 "General Project Description" (see Section 1.5.4.2 "LNG Vessel Loading Facility Construction").

Berthing and mooring configurations would be able to accommodate LNG vessels with capacities between 125,000 and 218,000 m^3 (LNG-Flex), as well as LNG barges with capacities of approximately 15,000 m^3. It is currently projected that, on average, one to two LNG carriers per week and an additional one to two LNG barges per week would make port calls at the Project terminal when operating at full plant capacity. Current projections of port call frequency are based on the maximum nominal LNG output of 8.0 mtpa and typical ship and barge sizes. The actual number of port calls per week will be determined by contracts that are subsequently executed and the capacity of the specific ships and barges used. The maximum number of vessel and barge transits per year will be determined by the U.S. Coast Guard as part of the Waterway Suitability Assessment process.

9.1.5 LNG Truck Loading

The Project would include facilities that allow a portion of the LNG to be loaded onto trucks for road distribution to LNG refueling stations in Louisiana and surrounding states. The LNG truck-loading area would include the following main facilities: cryogenic pipework (loading and vapor return) from the LNG storage tank(s) to the LNG truck-loading area; flexible cryogenic hoses (loading and vapor return) for filling; control panel; shelter; and a turning circle for LNG trucks. The capacity of the LNG trucks would be approximately 12,500 gallons (47 m^3) with a loading flow rate of approximately 265 gallons per minute (60 m^3 per hour). The anticipated volume of LNG to be delivered by truck once the Project is fully operational is about 2,461 m^3 per year (650,000 gallons per year).

It is currently projected that, on average, one truck would be loaded per week at the proposed facility when operating at full capacity and more LNG fueling stations become operational in Louisiana and neighboring states. Following the commissioning of the first two trains, Magnolia is initially projecting that their market share would allow for approximately 26 trucked cargos annually (12,500 gallons average per cargo) based on the existing LNG fueling stations currently in operation and projected to be constructed in Louisiana and Texas. As the market develops and more LNG refueling stations become operational, Magnolia would seek to increase market share, doubling the trucked cargos annually from the Magnolia LNG facility. For additional information, refer to RR 1, "General Project Description" (see Section 1.2, "Purpose and Need").

9.1.6 Feed Gas and Interconnect Pipeline

Feed gas would be transported to the site boundary via an existing 42-inch interstate gas pipeline owned and operated by Kinder Morgan Louisiana Pipeline (KMLP) that passes beneath the Project site near the southern boundary. The KMLP pipeline would be accessed within the Project site boundary. A short interconnect pipeline of approximately 75 feet to be located entirely within the Project site would tie-in the existing underground pipeline to the Gas Gate

Station. The Gas Gate Station would include an incoming interconnect pipeline, a filter/separator, custody transfer meter(s), a pressure regulator, an emergency shutdown (ESD) valve, and a gas analyzer. The short interconnect pipeline, the Gas Gate Station, the modification of certain existing KMLP delivery meter facilities to make them bidirectional, and the installation of new compression facilities near Eunice, Louisiana, will be built, owned, and operated by KMLP and, as such, will require a separate filing by KMLP with the FERC under Section 7(c) of the Natural Gas Act as explained in RR 1, Section 1.13, "Transportation of Feed Gas to the Magnolia LNG Project." A binding precedent agreement related to these facilities and up to 1.4 billion standard cubic feet per day of firm transportation on KMLP's pipeline was executed on January 28, 2014, between KMLP and Magnolia.

9.2 AIR QUALITY

9.2.1 Climate and Meteorology

The dispersion of air pollutants depends upon many factors, including meteorological conditions. All construction activities and operation of the Project would occur in southwestern Louisiana. Climate and meteorology data, normal and mean temperatures, humidity, precipitation, and winds were obtained from the National Oceanic and Atmospheric Administration (NOAA) Local Climatological Data product for Lake Charles, Louisiana. Modification of gas pipeline facilities owned by KMLP would occur in Acadia and Evangeline Parish. Climate and meteorological data associated with the facilities KMLP would construct and operate in order to deliver natural gas via its interstate pipeline to the Project site would be presented by KMLP, separately.

The Project area's general climate classification is humid subtropical with a strong maritime influence. The large of amount of water surface in the local area and proximity to the Gulf of Mexico produce the humid maritime conditions experienced in the area. The predominant wind direction is from the south for much of the year, which tends to subdue extreme summer heat and shorten the duration of winter cold outbreaks, but also increases relative humidity in the area. During winter months, the highest wind speeds occur with the wind direction being predominantly from the north.

January is typically the coolest month, followed by December and February; the months of June through September are the warmest (NOAA 2012). Precipitation is distributed fairly evenly throughout the year, but peaks in June and July. The area rarely receives snow; the annual normal is 0.1 inches with the maximum monthly being 4 inches which occurred in January 1973.

Normal annual average relative humidity is 79 percent. Humidity above 85 percent occurs very often overnight throughout the year. Climate normals are shown in Table 9.2-1.

Table 9.2-1 Baseline Climate Data (1981-2010) for Lake Charles, Louisiana

Month	Mean Maximum Temperature (°F)	Mean Minimum Temperature (°F)	Mean Daily Temperature (°F)	Mean Precipitation (in.)	Mean Wind Direction	Mean Wind Speed (mph)
January	60.8	42.1	51.4	5.23	360	8.8
February	64.1	44.7	54.4	3.46	360	9.2
March	71.2	51.3	61.2	3.66	170	9.0
April	78.1	58.8	68.5	3.33	190	8.9
May	84.4	66.2	75.3	5.20	190	7.8
June	89.3	72.1	80.8	6.85	190	6.7
July	91.0	74.2	82.7	5.63	210	5.5
August	91.4	73.7	82.6	4.86	190	5.4
September	87.8	69.1	78.4	5.26	50	6.6
October	80.7	58.6	69.7	4.90	50	7.3
November	71.2	50.1	60.7	4.43	360	8.0
December	63.6	44.0	53.8	4.68	360	8.6
Annual	77.8	58.7	68.3	57.49	190	7.7

Source: NOAA 2012.

9.2.2 National and Louisiana Ambient Air Quality Standards

The Clean Air Act (CAA) of 1970, 42 U.S.C. 7401 *et seq.*, amended in 1977 and 1990, is the primary federal statute governing air pollution. The CAA designates six pollutants as criteria pollutants, for which National Ambient Air Quality Standards (NAAQS) have been promulgated to protect public health and welfare. The six criteria pollutants are particulate matter (including PM_{10} and $PM_{2.5}$), carbon monoxide (CO), sulfur dioxide (SO_2), nitrogen dioxide (NO_2), lead (Pb), and ground-level ozone (O_3). Volatile organic compounds (VOCs) are not considered a criteria pollutant, but are evaluated as precursors to ground-level ozone formation. Primary and secondary standards are in place for criteria pollutants. Primary standards are designed to protect human health; secondary standards focus on protection of plant and animal life, buildings and other items in the public interest. Louisiana has adopted the Federal primary and secondary NAAQS. The standards are shown in Table 9.2-2.

Louisiana has also promulgated ambient air quality standards for toxic air pollutants (TAPs) in Title 33, Environmental Quality, Part III, Air, Chapter 51 (Louisiana Administrative Code [LAC] 33:III.51). The ambient air standards are applied in modeling evaluation of TAPs that exceed minimum emission rates only at major sources. A major source is defined in LAC 33:III.5103 as one that emits 10 tons per year (tpy) of a single TAP or 25 tpy of any combination of TAPs.

9.2.3 Existing Air Quality and Attainment Status

Calendar years 2010 to 2012 air quality monitoring data from the U.S. Environmental Protection Agency (USEPA) AirsData monitor values database was reviewed to characterize background air quality for regulated criteria pollutants (USEPA 2012). Air quality monitoring stations in proximity to the Project area were considered for obtaining monitored values. Because not all pollutants are monitored at each site, multiple monitoring sites are needed to characterize air quality. Four monitor sites were selected (Westlake, Lake Charles and Lafayette, Louisiana, and Jefferson County, Texas).

These monitoring sites have been established by the respective state air quality agencies (LDEQ for the Louisiana sites and TCEQ for Jefferson County, Texas) for monitoring population exposure to air pollutants. The sites are part of the State and Local Air Monitoring Stations (SLAMS), a national network established by the USEPA and implemented by state agencies to carry out the USEPA's monitoring requirements. States must follow strict guidelines with respect to siting the monitoring station and the type of equipment to be used, calibration frequency, and data recovery (e.g., monitoring stations must achieve a specific percent of valid data). These stations are sited in accordance with USEPA requirements.

The Westlake monitor site is 10.7 miles (17.2 kilometers [km]) north of the Project site. The Lake Charles site is 6.7 miles (10.8 km) northeast of the Project site. The Jefferson County (Nederland High School) monitoring site for CO is 43.7 miles (70 km) to the west. Terrain is flat at the monitoring sites and land use consists of a mix of residential, commercial, and industrial uses, similar to the proposed Project location. The Lafayette Parish (Cajundome) monitoring site for PM_{10} is 75 miles (121 km), east of the Project site, is characterized by flat terrain that is more urbanized than the Project site. PM_{10} concentrations measured in Lafayette Parish are conservative (i.e., likely higher) values than for the Project site due to the higher degree of urbanization in Lafayette Parish resulting in increased generation of PM_{10} emissions.

Background concentration data and primary NAAQS are shown in Table 9.2-2. Note that for lead, the USEPA data set does not currently provide the rolling three-month maximum statistic over the required three-year period; therefore no data are available for comparison to the NAAQS for lead at this time. In addition, monitoring for PM_{10} in Lake Charles ceased in 1997 and is currently not performed in southwestern Louisiana or nearby areas of Texas; therefore, data from the closest available monitor were used. Monitoring ceased in Lake Charles due to continued demonstration of compliance with the NAAQS for PM_{10} and a shift in priority of labor and funding resources to monitoring ambient concentrations of $PM_{2.5}$.

Table 9.2-2 Background Ambient Air Quality (2010 to 2012) and Ambient Air Quality Standards

Air Pollutant	Averaging Period	Statistic	Monitor Values [a]	Monitoring Site (Site ID)	Primary NAAQS [b]
Sulfur Dioxide (SO_2)	1-Hour	99th Percentile of daily 1-hour maximum averaged over 3 years	38 ppb	Westlake LA (220190008)	75 ppb
Carbon Monoxide (CO)	1-hour	Not to be exceeded more than once per year	1 ppm	Jefferson Co. TX (482451035)	35 ppm
	8-hour		0.5 ppm	Jefferson Co. TX (482451035)	9 ppm
Nitrogen Dioxide (NO_2)	1-Hour	98th percentile averaged over 3 years	32 ppb	Westlake LA (220190008)	100 ppb
	Annual	Annual mean	15.6 ppb	Westlake LA (220190008)	53 ppb
Ozone (O_3)	8-Hour	Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years	69 ppb	Westlake LA (220190008)	75 ppb
Particulate Matter of 10 microns in diameter or less (PM_{10})	24-Hour	Not to be exceeded more than once per year on average over 3 years	84 (1st max) 73 (2nd max) $\mu g/m^3$ [c]	Lafayette LA (220550007)	150 $\mu g/m^3$
Particulate Matter of less than 2.5 microns in diameter ($PM_{2.5}$)	24-Hour	98th percentile averaged over 3 years	20.7 $\mu g/m^3$	Lake Charles LA (220190010)	35 $\mu g/m^3$
	Annual	Annual mean averaged over 3 years	8.9 $\mu g/m^3$	Lake Charles LA (220190010)	12 $\mu g/m^3$
Lead (Pb)	Rolling 3-month	Not to be exceeded	(d)	-	0.15 $\mu g/m^3$

Source: USEPA AirsDatabase 2013.

Notes:

(a) Monitor value shown matches the statistic of the NAAQS. 3 year averages are formed from 2010 to 2012 data. For CO, value shown is maximum 2nd highest occurring in the 2010 to 2012 period. For NO2 annual, value shown is highest annual mean from the period 2010 to 2012.

(b) Secondary standards are promulgated for some pollutants and are generally the same as or less stringent than primary standards.

(c) Values shown are maximum 1st high and maximum 2nd high from 2010 to 2012 data. Monitoring for PM_{10} 24-hour is not performed in south-western Louisiana. Closest monitoring site is Lafayette, approximately 75 miles east of Magnolia.

(d) Monitoring for lead is not performed in south-western Louisiana. Closest historical monitoring site is in Beaumont, Texas. Historical data at that location have shown compliance with the NAAQS.

Key:

$\mu g/m^3$ = micrograms per cubic meter.

NAAQS = National Ambient Air Quality Standards.

ppb = parts per billion.

ppm = parts per million.

Calcasieu Parish is located in the Southern Louisiana-Southeast Texas Interstate Air Quality Control Region. Calcasieu Parish is designated as attainment/unclassifiable for all criteria pollutants, including an attainment designation for the 8-hour ozone NAAQS granted on June 15, 2004. Due to a previous marginal ozone nonattainment designation for the now revoked 1-hour ozone NAAQS, Calcasieu Parish submitted, received USEPA approval on, and implemented a maintenance plan for the revoked 1-hour ozone NAAQS. According to Section 110(a)(1) of the CAA and guidance issued by the USEPA on May 20, 2005 (USEPA 2005), at the time areas designated attainment for the 8-hour ozone NAAQS that are attainment for the 1-hour ozone NAAQS with a maintenance plan in place must develop a revised 10-year maintenance plan under Section 110(a)(1) of the CAA. A maintenance plan for Calcasieu Parish for the revoked 1-hour ozone NAAQS under Section 110(a)(1) of the CAA was submitted, approved by the USEPA, and has been in place since 2004, with its 10-year period ending in December 31, 2014. At the end of the 10-year maintenance plan period, a second 10-year plan is not required (see item 9 in USEPA 2005). Contingency measures in the existing approved 110(a)(1) maintenance plan remain in effect and these measures may be triggered if Calcasieu Parish exceeds the 8-hour ozone standard after December 31, 2014. Finally, a Section 110(a)(1) maintenance plan is not subject to any conformity obligations (USEPA 2005).

In addition, there are no nonattainment or maintenance areas through which LNG vessels would pass while transiting the Calcasieu River in route to the Gulf of Mexico. Once in the Gulf of Mexico, they would remain away from shore areas and not pass through nonattainment or maintenance areas.

9.2.4 Applicable Regulations and Permitting

This section summarizes the federal regulatory requirements for greenhouse gases (GHGs), Prevention of Significant Deterioration (PSD), New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and Title V Operating Permits. Applicable Louisiana air quality regulations also are summarized.

9.2.4.1 Federal Regulations

New Source Review

New Source Review (NSR) refers to the preconstruction permitting programs under Parts C and D of the CAA. NSR must be addressed before construction can begin on new major sources or major modifications to existing major sources. The PSD program is the NSR permitting program for sources located in attainment areas (below the NAAQS) and unclassified areas (areas for which there is insufficient information to determine attainment status). For sources located in nonattainment areas, the NSR permitting program is the nonattainment new source review (NNSR) program. Emission source thresholds for nonattainment areas are lower than the emission source thresholds for attainment areas. The Project location is unclassifiable/attainment and, therefore, is compared to attainment area major source NSR thresholds.

The major source attainment area NSR thresholds are either 100 tpy or 250 tpy. The 100 tpy threshold applies only to 28 distinct source categories listed in 40 Code of Federal Regulations (CFR) 52.21. The Project does not belong to any of the 28 source categories; therefore, the applicable major source threshold is 250 tpy per criteria pollutant. Estimated operational emissions would be above 250 tpy for NO_X and CO (see Section 9.2.6.1, "Emission Estimates"); therefore, the Project is subject to major source NSR permitting. Once a facility triggers PSD due to one or more pollutants above 250 tpy, other air pollutants that exceed significant emission rates (as defined within PSD regulations) would be included within the PSD review. Table 9.2-3 provides a comparison of facility emissions (including only emissions subject to permitting) to PSD significant emission rates. This table also indicates the air pollutants included in the PSD review.

Table 9.2-3 Comparison of Facility Emissions to PSD Significant Emission Rates

Air Pollutant	Total Facility Emissions (tons per year)	PSD Significant Emission Rates (tons per year)	Subject to PSD?
Nitrogen Oxides (NO_X)	1,153.55	40	Yes
Carbon Monoxide (CO)	804.04	100	Yes
Volatile Organic Compounds (VOCs)	68.91	40	Yes
Particulate Matter (PM)	87.88	25	Yes
Particulate Matter 10 microns or less in diameter (PM_{10})	87.82	15	Yes
Particulate Matter less than 2.5 microns in diameter ($PM_{2.5}$)	87.78	10	Yes
Sulfur Dioxide (SO_2)	133.80	40	Yes
Hydrogen Sulfide (H_2S)	3.83	10	No
Total Reduced Sulfur Compounds (including H_2S)	3.83	10	No
Greenhouse Gases (GHGs; as Carbon Dioxide Equivalents [CO_2e])	2,114,530.54	75,000	Yes

Greenhouse Gas Mandatory Reporting Rule and Tailoring Rule

The USEPA has promulgated rules requiring monitoring, reporting, and recordkeeping for GHGs that began in calendar year 2010. The final mandatory reporting rule was published in the *Federal Register*, at 74 Fed. Reg. 56,260 (Oct. 30, 2009). A facility is required to report its GHG emissions if its aggregate maximum rated heat input from all combustion sources is greater than 30 million metric British thermal units per hour (MMBtu/hr) and the facility emits more than 25,000 metric tpy of carbon dioxide equivalent (CO_2e). Magnolia would be required to report GHG emissions since the maximum heat input from all sources would be above 30 MMBtu/hr and annual emissions of GHGs would be above 25,000 metric tpy.

The USEPA also has promulgated the PSD and Title V Greenhouse Gas Tailoring Rule (*see* 75 Fed. Reg. 31,514 [June 3, 2010]). The Rule was phased-in using two steps. The first phase-in step of the tailoring rule began on January 2, 2011, and the second phase-in became effective July 1, 2011. New sources and existing sources not previously subject to Title V that emit at least 100,000 tpy CO_2e became subject to PSD and Title V requirements. Also, sources that have a potential to emit (PTE) of at least 100,000 tpy CO_2e and that undertake a modification that increases net emissions of GHGs by 75,000 tpy CO_2e will be subject to PSD requirements. Estimated PTE for GHGs for the Project is above 100,000 tpy CO_2e, therefore the Project is subject to PSD review for GHG.

New Source Performance Standards

NSPS regulations are issued for categories of sources that cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The standards apply to new stationary sources of emissions, i.e., sources whose construction, reconstruction, or modification began after a standard for those sources was proposed. When an NSPS applies at a facility, the facility must also comply with NSPS Subpart A (General Provisions).

NSPS Subpart Dc (Standards of Performance for Small Industrial, Commercial and Institutional Steam Generating Units) is also promulgated by the USEPA in 40 CFR Part 60. This NSPS applies to steam-generating units constructed after July 9, 1989, and that have maximum heat input capacity of 100 million British thermal units (MMBtu) per hour or less. The auxiliary boilers that are part of each liquefaction train are subject to NSPS Subpart Dc because they would be constructed after the applicability date and would have maximum heat input capacity of less than 100 MMBtu/hr.

NSPS Subpart IIII (Standards of Performance for Compression Ignition Internal Combustion Engines) for various engine sizes and types has been promulgated by the USEPA in 40 CFR Part 60. These standards implement Section 111(b) of the CAA. Stationary compression ignition internal combustion engines for use with emergency electric generators and firewater pumps are proposed as part of this project, therefore NSPS Subpart IIII applies.

NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines) regulates emissions of NO_X and SO_2 from combustion turbines. The applicability thresholds are a heat input rating (based on the higher heating value of the fuel) at peak load equal to or greater than 10 MMBtu/hour and manufactured after February 18, 2005. Because the proposed turbines are above these applicability thresholds, NSPS Subpart KKKK will apply.

National Emission Standards for Hazardous Air Pollutants Applicability

Section 112 of the CAA authorized the USEPA to develop technology-based standards that apply to specific categories of stationary sources that emit hazardous air pollutants (HAPs). These standards are referred to as National Emission Standards for Hazardous Air Pollutants (NESHAP) and are found in 40 CFR 61 and 40 CFR 63. NESHAP can apply to major and/or

area (minor) sources of HAPs. The USEPA develops national priorities for NESHAPs that focus on significant environmental risks and noncompliance patterns.

For the Magnolia LNG facility, the annual emissions of each individual HAP would be less than 10 tpy and the total annual emissions of all HAPs would be less than 25 tpy. Therefore, the facility would be an area (minor) source of HAPs.

NESHAP Subpart YYYY regulates HAP emissions from stationary combustion turbines located at major emission sources. Since the Project would not be a major source of HAPs, NESHAP Subpart YYYY does not apply to the proposed gas turbines.

NESHAP for Reciprocating Internal Combustion Engines (RICE) amendments were promulgated under 40 CFR Part 63, Subpart ZZZZ, by the USEPA. The original major source NESHAP for RICE was amended to include those with a site rating of 500 horsepower or less located at major sources, and new and reconstructed stationary RICE located at area sources. Based on the potential to emit for HAPs, Magnolia would be an area source. The RICE proposed for this Project includes the engines used for the emergency generators, the fire water pumps, and the deluge pumps. Therefore Subpart ZZZZ is applicable. In accordance with 40 CFR 63.6590(c), compliance with Subpart ZZZZ will be achieved through compliance with NSPS Subpart IIII.

The USEPA finalized NESHAPs Subpart DDDDD for Major Sources: Industrial-Commercial-Institutional Boilers and Subpart JJJJJJ for Area Sources: Industrial-Commercial-Institutional Boilers on February 1, 2013. Subpart DDDDD applies to facilities emitting 10 tpy or more of an individual HAP or 25 tons or more of total HAPs. Subpart JJJJJJ applies to sources emitting below the major source thresholds that fire coal, oil, or biomass; Subpart JJJJJJ does not apply to gas-fired boilers. Emission estimates for HAPs (see Section 9.2.6.1, “Emission Estimates”) indicate that the facility would be considered an area source for HAPs, however the auxiliary boilers meet the definition of gas-fired boilers in 40 CFR 63.11237 and thus are not subject to Subpart JJJJJJ.

General Conformity

Section 176 of the 1990 CAA Amendments required the USEPA to promulgate rules to ensure federal actions conform to the appropriate State Implementation Plan (SIP). These rules, known together as the General Conformity Rule (40 CFR 51.850-.860 and 40 CFR 93.150-.160), require any federal agency responsible for an action in a non-attainment or maintenance area for any criteria pollutant to determine if the action conforms to the applicable SIP or is exempt from the General Conformity Rule requirements. This means federally supported or funded activities will not:

- Cause or contribute to any new air quality standard violation;
- Increase the frequency or severity of any existing standard violation; or
- Delay the timely attainment of any standard, interim emission reduction or other milestone.

The USEPA amended the General Conformity Rule in 2010 (*see* 75 Fed. Reg. 17,253 [Apr. 5, 2010]). Included in the amendment is the exclusion of emissions regulated by any permit issued under minor and major NSR from a General Conformity applicability analysis. Previously, only major NSR permit emissions were excluded.

A conformity determination is required for each pollutant where the total of direct and indirect emissions caused by a federal action (such as a FERC action) would equal or exceed de-minimis levels as specified in 40 CFR Part 93.153 with the exceptions specified in 40 CFR Part 51.853(c), (d), or (e). Conformity evaluations are not required for areas that are in attainment for NAAQS.

Calcasieu Parish is designated as attainment for all pollutants. Other parishes or counties through which marine vessels associated with the Project may pass also are designated as attainment. General Conformity does not apply in attainment areas. A maintenance plan for Calcasieu Parish for the revoked 1-hour ozone NAAQS under Section 110(a)(1) of the CAA is in place, with its 10-year period ending on December 31, 2014. However, this maintenance plan is not subject to any conformity obligations (USEPA 2005). Therefore no further analysis is required under General Conformity.

9.2.4.2 Louisiana Regulations

State air quality rules govern the issuance of air permits for construction and operation of a stationary emission source. For larger facilities subject to major NSR, review and approval at the federal level may be required. For new facilities, classification as a minor or major source depends on the quantity of potential emissions and the existing air quality designation of the project location. Louisiana's state air quality regulations are found in LAC, Title 33, Part III (Air).

9.2.4.3 Air Permitting Requirements

The Louisiana Department of Environmental Quality (LDEQ) administers the air permit programs for the Project. A new facility must apply for and obtain an air quality permit prior to commencing construction. After the Project completes construction and commences operation, the Project would be governed by an operating permit. The USEPA may review a project's air permit application if the PTE for the proposed project exceeds PSD major source thresholds. These thresholds are listed in Title 40 CFR §52.21(b)(1)(i).

Title V Operating Permit Applicability

The federal Title V operating permit program is delegated to the LDEQ. The Louisiana Air Operating Permit program is codified in LDEQ Title 33 Environmental Quality, Part III Air, Chapter 3 and 5. The major source threshold for the Title V operating permit program is 100 tpy for criteria pollutants, 10 tpy for individual HAPs, and 25 tpy for any combination of HAPs. Estimated site-wide PTE emissions for NO_X, CO, VOC, and HAPs for the Project are above major stationary source Title V thresholds therefore, the Project is subject to the Title V Operating Permit program.

Class I Areas

Two factors determine potential effects on federal Class I areas: magnitude of emissions and distance to the Class I area. After construction of the Project, the PTE, with controls, is above 250 tpy for all criteria pollutants; therefore the facility is a major emission source of criteria pollutants under NSR PSD regulations. The closest Class I area to the Project site is the Breton National Wildlife Refuge (approximately 420 kilometers to the east-southeast off the coast of Louisiana/Mississippi). Typically, a separation distance greater than 300 kilometers between an emission source and a Class I area preclude the need for further Class I air quality analyses.

9.2.5 Air Pollutant Emissions – Construction

Construction activities would result in temporary, localized emissions that would last for the duration of the construction period. Project components would be constructed during various months beginning in mid-2015 (July 1, 2015) with proposed facilities placed into service by June 2018 as shown on the Project schedule included in RR 1, "General Project Description" (see Appendix 1.E, "Project Schedule"). Emissions from construction are not expected to result in a violation of any applicable ambient air quality standard; construction equipment would be operated on an as-needed basis during daylight hours only.

9.2.5.1 Construction Emissions – Methodology

An inventory of non-road equipment, vessels, on-road vehicles, off-road vehicles, and expected activity levels (either hours of operation or miles travelled) were developed based on expected duration of construction at the site. The level of activity for each piece of construction equipment was combined with emission factors obtained from various sources (as described below) resulting in estimates of annual construction emissions for each year of construction.

The construction schedule and anticipated tasks are defined in detail in RR 1, "General Project Description." For the purpose of estimating construction emissions, construction is divided into six phases consisting of the following:

- **Site Preparation**, consisting of site clearing by removing debris, followed by stripping/grubbing topsoil (stockpiled on-site), cut-fill and rough grading operations, construction of drainage swales and the short (approximately 1,500 feet) heavy-haul road from the construction workspace immediately east of the Project site and preparation for foundations. Equipment used in this phase includes dump trucks, bulldozers, backhoes, trackhoes and drum rollers. See Appendix 9.A, Phase I for equipment lists, quantity, utilization, emission factors, horsepower and fuel type.

- **LNG Storage Tanks**, consisting of foundation construction using concrete piles driven by hydraulic pile drivers and site-erected tank construction. See Appendix 9.A, Phase II for equipment lists, quantity, utilization, emission factors, horsepower and fuel type.

- **Balance of Plant**, consisting primarily of foundation construction for the LNG trains, receipt of the LNG train modules at the temporary work yard, transport from the work yard to the Project site using heavy crawlers, assembling each train, and completion of other plant equipment such as emergency water pumps, site buildings, onshore components of the LNG vessel loading facility, among others. This phase includes use of pile drivers for the LNG vessel loading facility as well pile-driving required for the LNG trains, storage tanks, and other site structures. See Appendix 9.A, Phase III for equipment lists, quantity, utilization, emission factors, horsepower and fuel type.

- **Architectural/Building Construction**, during which on-site buildings and other architectural components would be constructed in 2016 and 2017 using the equipment type and quantity identified in Appendix 9.A, Phase IV.

- **Marine Work**, consisting of construction of the LNG vessel loading facility, including the berthing and waterway access area. The berthing and waterway access area would be constructed using a combination of onshore excavation (using backhoe and trackhoe equipment) and dredging using a hydraulic cutterhead suction dredge mounted on a self-propelled vessel. Dredging emissions are included in this phase. Bulkhead construction would consist of pile-driving steel sheet at the ends of the berthing basin and armoring with rock at the base of the bulkhead; breasting dolphins would be constructed by pile-driving 8-foot-diameter steel pilings into competent foundation soils. See Appendix 9.A, Phase V for equipment lists, quantity, utilization, emission factors, horsepower, and fuel type.

- **Miscellaneous Construction**, consisting of equipment not tied to a specific task but that would be used for general construction activities throughout the duration of construction. Equipment would consist of pickup trucks/vans, water trucks, forklifts and utility carts. See Appendix 9.A, Phase VI for equipment details.

Construction materials would be delivered to the site primarily by barge. Unloading would occur at the existing construction yard immediately east of the Project site, at the Dynamic Industries, Inc. facilities. A total of 50 barge loadings were used to estimate emissions associated with construction material delivery. In addition, large quantities of concrete would be used to construct the Project. Cement would be sourced from existing concrete plants in the area within 3 to 5 miles of the Project site. Emissions associated with truck transport of concrete are included in the construction emission estimate in several of the construction phases (LNG storage tanks, balance of plant and architectural buildings).

Emission factors for non-road on-land equipment, including off-road trucks, were obtained from runs of the USEPA NONROAD Emission Factor Model, Version 2008a (USEPA 2008) for Calcasieu Parish for the construction years 2015, 2016, and 2017.

Two types of marine vessels would be used during construction. Tugboats would be used for barge delivery of material required to construct the Project. Dredging of the berthing and waterway access areas would be accomplished using a typical medium-sized (approximately 1,500 horsepower) dredging vessel. Emission estimates for construction activities are based on

the anticipated duration of use of each vessel type during the construction period, the vessels' engine characteristics and duty cycles, and emission factors from the USEPA guidance document "Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories" (ICF International 2009). Since vessel contractors have not yet been selected for the Project, vessel emission Tiers are not known; thus, Tier 0 vessels were assumed for emission estimation purposes.

On-road vehicle emission factors were determined using the USEPA Motor Vehicle Emission Simulator (MOVES) 2010b mobile source emission factor model. The model was run for each year of construction activity using the model's internal mobile source database tailored to Calcasieu Parish. Emission factors for passenger cars and trucks (sport utility vehicles) and short-haul and long-haul trucks were produced. These factors (in grams per mile of vehicle activity) were combined with estimates of miles travelled by cars and trucks to determine annual on-road emissions from construction activities.

A spreadsheet-based emission estimate procedure was used to combine the construction schedule, inventory of vessels/equipment/on-road vehicle/off-road vehicle types, quantity and duration of use, and emission factors to determine total Project construction emissions. Detailed calculations are provided in Appendix 9.A.

Fugitive dust emission levels would vary in relation to moisture content, composition, activity level and volume of soils during construction. Fugitive dust would be produced primarily during the initial phase of preparing the site for construction of the Project when the site would be cleared of debris and leveled using cut-and-fill techniques and graded. In addition, approximately 131,200 cubic yards of soil from upland areas would be excavated and placed on-site. Existing off-site paved roads would be used to access the Project location with no new road construction or modifications required for Project purposes. There would be limited unpaved road travel on-site due to the compact footprint of the construction site, short distance (less than 1,500 feet) of the heavy-haul road, and slow speeds used to transport Project components and other raw materials from the adjacent construction yard to the Project site (utilizing self-propelled modular transporters for large Project components).

The fugitive emission estimate consists of contributions from general site construction work based on acres of activity, earth-moving fugitive dust emissions based on quantity of soil moved, and unpaved road travel based on weight of vehicles. Magnolia would implement dust control measures as necessary during certain construction activities, such as transporting soil or rock, trenching, and use of access roads; these measures would be specified in a control plan. Fugitive dust emissions associated with construction would not contribute to degradation of NAAQS.

9.2.5.2 Construction Emissions Results

Construction equipment emissions and fugitive dust emissions are summarized in Table 9.2-4.

Table 9.2-4 Total Construction Emissions By Year

Activity	Emissions (tons) VOC	NO_X	PM_{10} and $PM_{2.5}$	CO	SO_2	CO_2e
Calendar Year 2015						
Site Preparation	0.6	6.4	0.7/0.7	3.1	0.3	1,817
LNG Tank Construction	1.0	10.1	1.0/1.0	13	0.5	2,599
Balance of Plant	0.5	5.3	0.5/0.5	5.2	0.3	1,435
Architectural	0.0	0.0	0.0	0.0	0.0	0.0
Marine (dock, jetty, dredging)	0.4	11.5	0.4/0.4	3.0	1.1	954
Material Transport via Tug/Barge	0.0	0.0	0.0	0.0	0.0	0.0
Construction Management (water trucks, pickup trucks, etc.)	0.1	0.6	0.1/0.1	2.4	0.1	225
Construction Mobile Sources (worker commutes)	0.0	0.1	0.0/0.0	1.6	0.0	238
Fugitive dust	--	--	14.9/1.5	--	--	--
Total	**2.6**	**34**	**17.6/4**	**27**	**2.2**	**7,268**
Calendar Year 2016						
Site Preparation	0.0	0.0	0.0	0.0	0.0	0.0
LNG Tank Construction	4.1	25	2.9/2.9	93	1.5	8,739
Balance of Plant	0.4	2.9	0.4/0.3	5.8	0.2	1,010
Architectural	1.4	3.7	0.2/0.2	49	0.2	856
Marine (dock, jetty, dredging)	1.2	12	0.8/0.8	31	1.0	2,523
Material Transport via Tug/Barge	0.5	26	0.6/0.6	5.0	2.6	1,385
Construction Management (water trucks, pickup trucks, etc.)	0.1	0.8	0.1/0.1	0.5	0.1	427
Construction Mobile Sources (worker commutes)	0.0	0.2	0.0/0.0	2.8	0.0	408
Fugitive dust	--	--	14.3/1.4	--	--	--
Total	**7.8**	**71**	**19.3/6.2**	**187**	**5.6**	**15,348**
Calendar Year 2017						
Site Preparation	0.0	0.0	0.0	0.0	0.0	0.0
LNG Tank Construction	2.9	12	1.5/1.5	88	0.7	4,022
Balance of Plant	0.2	0.9	0.1/0.1	4.6	0.1	372
Architectural	1.2	2.6	0.2/0.1	46	0.1	654
Marine (dock, jetty, dredging)	0.4	1.7	0.2/0.2	12	0.1	858
Material Transport via Tug/Barge	0.0	0.0	0.0	0.0	0.0	0.0
Construction Management (water trucks, pickup trucks, etc.)	0.1	0.6	0.1/0.1	0.4	0.1	396
Construction Mobile Sources (worker commutes)	0.0	0.2	0.0/0.0	2.8	0.0	408
Fugitive dust	--	--	14.3/1.4	--	--	--
Total	**4.8**	**18**	**16.4/3.4**	**154**	**1.1**	**6,710**

Potential projects in proximity to the Project include three proposed projects within 0.5 mile of the Project site. These projects are G2X Energy, the Trunkline LNG, LLC, Lake Charles Export Terminal (Trunkline LNG), and the Lake Charles Fisheries Research Center. Two of these projects, G2X Energy and Trunkline LNG, anticipate a construction period beginning in 2014 and ending in 2017 (see Table 1.9-1 in RR 1, "General Project Description," Section 1.9 "Cumulative Impact Analysis"). This construction period would overlap with the Project's construction period of mid-2015 through 2017. The construction of the Lake Charles Fisheries Research Center would not overlap with the construction of the Magnolia LNG Project and the construction schedule will not be established until after the facility is designed; therefore, it is not possible to speculate on its potential to contribute to a cumulative impact. For additional information, please refer to Section 9.4 of this resource report.[1]

9.2.5.3 Construction Emissions – General Conformity

As noted in Section 9.2.4.1, "Federal Regulations," Calcasieu Parish and surrounding parishes are designated as in attainment with the NAAQS. General conformity does not apply to attainment area emissions. A maintenance plan for Calcasieu Parish for the revoked 1-hour ozone NAAQS under Section 110(a)(1) of the CAA is in place, with its 10-year period ending in June 2014. However, this maintenance plan is not subject to any conformity obligations (USEPA 2005). Therefore General Conformity does not apply to the Project's construction emissions since construction emissions would occur only in Calcasieu Parish.

9.2.6 Air Pollutant Emissions – Operation

Each of the four liquefaction trains would consist of the following emission sources:

- Two General Electric PGT25+G4 dry low NO_X gas turbines
- One auxiliary boiler
- One thermal oxidizer to treat emissions from the amine unit
- One ammonia vent
- Fugitive emissions from pipe flanges, valves and valve stems

The emission sources associated with each liquefaction train would operate continuously; the air permit application for the facility will request full-year operation for these sources.

[1] On February 6, 2014, a meeting was held with Jason Duet and Craig Gothreaux with the Louisiana Department of Wildlife and Fisheries (LDWF) regarding the Fisheries Research Center to gather additional information about the proposed facility, including the timing for its construction. The LDWF anticipates that it will be at least four years before ground is broken on the research center. So far, the LDWF has completed a high-level concept study of the center, started an environmental assessment of the project, and initiated coordination efforts with state and federal regulatory agencies to determine what permits are required. During the meeting, it was stated that funding for the project came from the Louisiana Oil Spill Coordinator's office as an early Natural Resources Damage Assessment (NRDA) project (paid for through early NRDA funding provided by BP) and they would turn the project over to the State Office of Facility Planning. Facility Planning would then issue the Request for Proposal for the design of the facility; once the facility is designed, they would issue bids for construction.

The facility also would contain the following emission sources:

- One cold gas flare for treating low temperature gases
- One warm gas flare for treating warm and high temperature process gases
- One diesel engine-driven emergency electric generator (1,000 kilowatts)
- Two diesel engine-driven emergency firewater pumps
- Two diesel engine-driven deluge water pumps
- LNG tanker vessels and attendant tugboats
- Tugboats/LNG barges
- Miscellaneous mobile sources associated with facility operations, including worker commuting vehicles and potential truck transport of LNG to regional highway LNG refueling sites

The additional facility emission sources listed above would operate on an intermittent or as-needed basis. The air permit application will request operating restrictions for the flares and diesel-engine generators and pumps to limit emissions. All diesel engine-driven equipment is provided solely for standby/emergency use. Mobile source emissions are not subject to air permitting in the state of Louisiana.

During operation, there is a potential that fugitive emissions would be produced from pipe flanges and valves and other components in gas or liquid service. Emission factors combined with component counts for compressors, flanges, relief valves and other potential emission sources have been used to estimate fugitive emissions.

In addition to stationary sources, operation of the Project would produce emissions from mobile sources including LNG tanker vessels, tugboat emissions produced during barge transport of LNG to local distribution facilities, worker commuting emissions, and potentially on-road truck emissions if the truck LNG distribution capability is also built.

9.2.6.1 Emission Estimates

Emission estimates for Project operation are shown in Table 9.2-5. Detailed calculations are provided in Appendix 9.B, "Operational Emissions," for each emission source. Appendix 9.B.1, Table 1 provides a facility-wide emission summary for all stationary and mobile sources. Appendix 9.B.1, Table 2 provides an emission summary for one LNG train (each LNG train is identical). Facility PTE is based on 8,760 hours of operation per year (full year), except that diesel engines powering the emergency generator, firewater pumps and deluge pumps are based on a limit of 500 hours per year and the warm and cold gas flares are based on 88 hours of operation treating gas releases with 8,760 hours per year of pilot gas operation. Mobile source emissions for LNG carriers and tugboats are based on frequency of operation to accommodate required LNG transport from the facility. Additional mobile source emissions include tugboat/barge LNG transport, operational worker commuting emissions and truck distribution of LNG.

Table 9.2-5 Potential Operation Emissions (tons per year) for the Project

Emission Source	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC	Ammonia	HAPs	CO_2e
Gas Turbines (8)	1,019	621	1.0	74.2	74.2	42	--	11.2	1,330,992
Thermal Oxidizers (4)	31.5	26.4	132	4.2	4.2	3.1	--	0.08	550,372
Auxiliary Boiler (4)	81	82.2	0.4	7.5	7.5	7.5	--	1.6	204,422
Ammonia Vent (4)	--	--	--	--	--	--	5.8	--	--
Subtotal LNG Trains	**1,132**	**729**	**133**	**86**	**86**	**53**	**5.8**	**12.9**	**2,085,786**
Emergency Generator	3.6	1.9	0.0	0.09	0.08	0.35	--	0.0	385
Emergency Firewater Pumps (2)	1.2	1.0	0.0	0.04	0.04	0.1	--	0.0	198
Deluge Pumps (2)	4.2	2.3	0.0	0.1	0.1	0.4	--	0.0	198
Warm Gas Flare	8.3	45.2	0.0				--	0.1	16,559
Cold Gas Flare	4.5	24.6	0.0				--	0.0	8,975
Fugitive Emissions	--	--	--	--	--	14.7	1.54	0.28	2,222
Subtotal Other Sources	**21.8**	**75**	**0.0**	**0.2**	**0.2**	**15.6**	**1.54**	**0.4**	**28,537**
LNG Vessels and Tugboats	329	42	3	15	15	19			21,396
Worker Commuting	0.06	0.8	0.01	0.01	0.01	0.01		<0.01	110
Tug/Barge Distribution	66	6	0	4	4	4		n/a	3,383
Truck Distribution	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01		<0.01	2
Subtotal Mobile Source	**395**	**9**	**3**	**15**	**15**	**19**		**<0.01**	**24,889**
Facility Total	**1,549**	**853**	**136**	**101**	**101**	**88**	**7.3**	**13.3**	**2,139,212**

Gas Turbines

The gas turbines would drive the refrigeration compressors. A total of eight gas turbines (two per LNG train) would be used. Gas turbines would be aero-derivative units utilizing inlet air cooling to cool inlet air to 50°F when ambient air temperature is above 50°F; the turbines would have dry-low NO_X combustors. Gas turbines are expected to operate full-time throughout the year; current estimates of startup/shutdown requirements are two events per turbine per year. A gas turbine startup event would take 10 minutes from initiating startup to full gas turbine load. Annual emission estimates of NO_X and CO for gas turbine startup and shutdown events are based on manufacturers' estimated emissions per event of 2.5 pounds NO_X and 2.9 pounds CO and two startup events per turbine per year. Annual NO_X and CO emissions for startup would be 40 pounds and 46 pounds, respectively. A gas turbine shutdown event requires eight minutes to complete from full-load operation to shutdown. The manufacturer-estimated emissions per shutdown event are 2.2 pounds NO_X and 3.0 pounds CO. Based on two shutdown events per turbine per year, the resulting annual emissions would be 35.2 pounds NO_X and 48 pounds CO. Total startup and shutdown emissions would be 75 pounds NO_X and 94 pounds CO annually.

Appendix 9.B.1, Table 3 provides detailed calculations for the gas turbine operational emissions.

Thermal Oxidizer

The thermal oxidizer would consist of a low NO_X burner firing upward into the base of a leg-supported, refractory-lined incinerator. A carbon dioxide (CO_2) waste gas stream containing hydrogen sulfide and benzene-toluene-ethylbenzene-xylene (BTEX) from the feed gas pre-treatment plant would enter the unit near the base of the incinerator vessel near the burner. This physical arrangement allows the burner to use the cool, inert waste gas as a means to reduce NO_X production during operation. The feed gas would mix with the waste gas in the combustion process to form the hot flue gas that would be discharged from the unit at the top. The estimated destruction efficiency for BTEX in the combustion process is 99.00 percent. Hydrogen sulfide is expected to fully oxidize to SO_2 with no emissions of sulfuric acid gas/mist anticipated.

Appendix 9.B.1, Tables 4 and 5 provide emission calculation details for the thermal oxidizer maximum and average conditions, respectively.

Auxiliary Boiler

The auxiliary boiler would combust a mixture of high British thermal unit (BTU) (feed gas and rich (heavy hydrocarbon) gas) and low BTU (holding and ship loading) fuel and inert gas (nitrogen) using two low NO_X burners, one for low BTU gas streams and one for high BTU gas streams. The percentage of each fuel type that would be in the fuel mixture fired in the boiler has been estimated based on preliminary process and vessel loading waste gas production. There are four potential gas mixture scenarios that could be used as fuel in the auxiliary boiler. These cases and the expected percent of time during the year each gas mixture would be fired in the auxiliary boiler are:

- Average Feed Gas Base Case (84.74 MMBtu/hr Higher Heating Value [HHV]) – 90 percent
- Rich Feed Gas Case (99.0 MMBtu/hr HHV) – 3.52 percent
- Ship Loading Case (94.33 MMBtu/hr HHV) – 5.48 percent
- High Inert Feed Gas Case (82.87 MMBtu/hr HHV) – 1 percent

The emission totals for the auxiliary boiler in Table 9.2-5 reflect operation on the four fuel mixtures in the percentages of time shown above. The fuel gas stream burned in the auxiliary boiler may contain trace amounts of H_2S and BTEX from the CO_2 removal system. The estimated destruction efficiency for these HAPs in the combustion process is 99.99 percent. The emission totals for these HAPs, shown in Table 9.2-5, include the post-combustion quantities of these HAPs produced by burning feed gas and the waste gas stream.

Appendix 9.B.1, Tables 6 through 10 provide emission calculations details for the auxiliary boiler and gas mixtures.

Ammonia Vent

The ammonia vent provides for pressure relief from the ammonia chilling plant. It is anticipated that the vent would operate during normal facility operations to maintain system pressure. Appendix 9.B.1, Table 11 provides details for the ammonia vent emission estimate.

Flare System

The flare system would include two flares: one warm flare (or process flare) and one cold flare (or marine flare). The purpose of the flare system is to dispose of gas streams that are released during start-up, shutdown, plant upsets, and emergency conditions. The Project is being designed to avoid continuous flaring. Both flares would be located adjacent to one another on a common structure supported by a common guy wire system. The source of the pressure relief flows to the flares are gas discharges from relief valves, depressurizing valves and pressure control valves throughout the LNG plant that open automatically during abnormal conditions.

The warm flare would handle wet/warm relief gases. Prior to the flare, piping in the warm flare system would collect relief fluids from feed gas pretreatment and other above ambient temperature processes. A warm flare knockout drum would be used to collect water and any free liquids prior to reaching the flare stack.

The cold flare system would handle cold relief fluids and gases. The system is designed for gases and fluids lower than ambient temperature such as from the cold section mixed refrigerant, boil-off gas section, and LNG tank venting system. The relief fluids would pass through a cold flare knockout drum prior to the relief flow reaching the flare stack. The cold liquids collected in the knockout drum would gradually vaporize to the flare.

Appendix 9.B.1, Tables 12 and 13 provide details for the flare emission calculations.

Emergency Use Diesel Engines

Diesel engines would be provided to operate an emergency electrical generator (1,000 kilowatts [kW]), two fire water pumps (250 kW each), and two LNG tank deluge water pumps (600kW each). Emissions for each unit are based on a limit of 500 hours per year and low sulfur fuel (sulfur content of 15 ppm). Appendix 9.B.1, Tables 14, 15 and 16 provide details for the emergency use engines.

Fugitive Sources

During facility operation, there is a potential that fugitive emissions from gas and liquid process streams would be released. Potential fugitive emissions may come from piping components, such as from pipe flanges and valves and other components. Component counts for seven separate process streams at the facility were derived based on preliminary design information provided in conjunction with RR 13. Appendix 9.B.2, Tables 17 and 18 *[PRIVILEGED]* provide the estimated component counts, process stream gaseous constituents, and emission factors.

LNG Vessel and Tugboat Operations

The Project location is within the North American Emission Control Area (ECA) designated by the International Maritime Organization (IMO) through Annex VI of the International Convention for the Prevention of Pollution from Ships (MARPOL). Key dates for the North American ECA are 2012 (1% sulfur fuel), 2015 (0.1% sulfur fuel) and 2016 (engine NOx emission after-treatment requirements).

LNG vessel emissions are based on a typical 175,000-cubic meter capacity vessel with compression ignition/electric propulsion. Propulsion emission factors are based on typical vessel engine manufacturer data for a Wartsila 50 DF operating primarily on natural gas with a small quantity of pilot marine gas oil fuel (0.1 percent sulfur). It is assumed the vessel primarily would operate on boil-off gas. Emissions are estimated for two trips per week over a round-trip distance from 12 miles offshore, up the Calcasieu River to the Project facility, maneuvering and docking, hoteling, and a return trip to a distance of 12 miles offshore. It is estimated that the vessel trip described above would require approximately 30 hours, with 18 hours included for hoteling while loading LNG at the Magnolia LNG facility. While hoteling during LNG loading, it is assumed the main propulsion engines would be shutdown with hoteling requirements supplied by auxiliary engines operating solely on marine gas oil. The LNG vessel emission estimate includes emissions from 6,000-horsepower tugboats that would assist the LNG vessel during the entire trip from/to the offshore location. Two tugboats would meet the LNG vessel offshore and escort it to a point approximately 3 miles from the Magnolia LNG terminal, where two additional tugs would join in assisting the LNG vessel to docking. While the LNG vessel is loading LNG, one tug would remain on standby, moored at the dock with only a hoteling generator in operation. The departure trip of the LNG vessel would essentially be a reverse of the inbound trip, applying the same number of tugboats. Appendix 9.B.1, Table 19 provides details for the LNG vessel/tugboats operations.

Tug/barge distribution of LNG is based on use of a large tug (approximately 6,000 horsepower) to push an empty barge to the Magnolia LNG loading dock and then push a barge loaded with LNG to a distribution point. The specific destinations for barge distribution of LNG are not known at this time, therefore the distance from the Project facility to the Gulf of Mexico and return (approximately 45 nautical miles round trip [approximately 50 statute miles]) was used in the emission estimate. An average speed of 3 knots results in an average round-trip duration of approximately 15 hours. Tug/barges are estimated to make up to two trips per week. Appendix 9.B.1, Table 19 shows emission estimate details associated with tug operation during barge loading, Table 20 shows the emission estimate details for the tug/barge transport.

On-Road Mobile Sources

On-road mobile source emissions (worker commuting and truck LNG distribution) are based on emission factors from a run of the USEPA MOVES model for Calcasieu Parish. Expected full-time employment data and potential residential locations from the Project traffic study were used to estimate annual round-trip miles travelled by workers commuting from the general area to the Project facility (40 directional trips by workers). The annual miles travelled were combined with emission factors from the USEPA MOVES model run to estimate annual

worker commute emissions. The round-trip distance for truck trips for distribution of LNG was based on the best potential route from the Project facility to Interstate 10 described in the traffic study (see Appendix 5.B in RR 5, "Socioeconomic") and assuming one truck trip per week. The potential number of truck trips is highly dependent on the development of local refueling stations for LNG or compressed natural gas vehicles. The annual miles travelled by the LNG distribution trucks were combined with heavy-duty truck emission factors from the MOVES run to estimate annual emissions. Appendix 9.B.1, Table 20 provides details for the emission estimate.

9.2.6.2 Ambient Impact Analysis

Magnolia is in the process of developing the ambient impact analysis. The ambient impact analysis will be based on proposed emission rates contained in the LDEQ air permit application. At this stage, emission rates in the LDEQ application are in draft form, thus the ambient impact analysis is preliminary only. The analysis will address the ambient impact of the proposed Project using dispersion modeling and photochemical grid modeling for ozone.

Magnolia has prepared two dispersion modeling protocols (see Appendix 9.C). The first protocol, dated January 15, 2014, describes modeling procedures to be used to support the LDEQ air permit application (Appendix 9.C.1). This protocol addresses modeling of the Project's stationary sources that are subject to air permit regulations and discusses procedures to be used if a cumulative impact analysis is required. For permitting purposes, if facility-only modeling results in modeled ambient concentrations above one or more significant impact levels (SILs), a cumulative source inventory will be developed and modeled in conjunction with the Project. The protocol received approval from the LDEQ on January 22, 2014.

For NEPA purposes, Magnolia prepared a second dispersion modeling protocol (Appendix 9.C.2). Magnolia has adapted the protocol approved by the LDEQ to include the LNG vessel and tugboat engine emissions in the modeling analysis and to address cumulative impacts in conjunction with nearby facilities.

Magnolia has prepared and submitted a photochemical modeling protocol to LDEQ and USEPA Region 6 (Appendix 9.C.3). Photochemical modeling is currently in process.

9.3 NOISE

Noise is defined as any unwanted sound. Sound is defined as any pressure variation that the human ear can detect. Humans can detect a wide range of sound pressures, but only the pressure variations occurring within a particular set of frequencies are experienced as sound. However, the acuity of human hearing is not the same at all frequencies. Humans are less sensitive to low frequencies than to mid-frequencies, and so noise measurements are often adjusted (or weighted) to account for human perception and sensitivities.

The unit of noise measurement is a decibel (dB). The most common weighting scale used is the A-weighted scale, which was developed to allow sound-level meters to simulate the frequency sensitivity of human hearing. Sound levels measured using this weighting are noted as dBA (A-weighted decibels; "A" indicates that the sound has been filtered to reduce the

strength of very low and very high frequency sounds, much as the human ear does). The A-weighted scale is logarithmic, so an increase of 10 dB actually represents a sound that is 10 times louder. However, humans perceive the 10 dBA increase as twice as loud, not 10 times louder.

Various descriptors that are commonly used to evaluate sound pressure levels over time include the following:

- Equivalent Sound Level, or L_{eq}, is the average of the sound energy over time. The L_{eq} integrates fluctuating sound levels over a period of time to express them as a steady-state sound level.

- Day-Night Average Sound Level, or Ldn, is equivalent to a 24-hour L_{eq}, but with a 10-dBA penalty added to nighttime noise levels (10:00 p.m. and 7:00 a.m.) to reflect the greater intrusiveness of noise experienced during this time.

- L_{max} is the maximum instantaneous noise level during a specific period of time.

9.3.1 Noise Regulations

The environmental sound level contributions from the proposed liquefaction equipment at the proposed Project facility are subject to the FERC noise regulation for new stations. Under these regulations, the noise attributable to any new natural gas compressor station must not exceed an Ldn of 55 dBA at any pre-existing noise sensitive area (NSA). In areas subject to steady noise levels throughout a 24-hour period, the Ldn noise level is about 6.4 dBA higher than the 24-hour L_{eq} because of the nighttime weighting factor. For a station that is operating continuously, an L_{eq} noise level of 48.6 dBA is equal to the FERC Ldn noise limit of 55 dBA. The FERC requirements stipulate that in addition to the Ldn 55 dBA limit, any applicable state or local noise regulations must be identified.

Calcasieu Parish noise regulations are contained in the Calcasieu Parish Police Jury Code of Ordinances, Chapter 18, Article VIII. However, these noise regulations do not prescribe numerical noise standards.

9.3.2 Existing Noise Levels

A noise survey was conducted by Ecology and Environment, Inc. beginning September 23 through September 25, 2013. The purpose of the survey was to characterize the existing noise environment around the proposed Project site. During the survey, continuous long-term average sound levels were measured statistically in consecutive 1-hour intervals at three NSAs as explained below. For a detailed description of methodology followed and conditions during the sound level measurements, see Section 4.0 of the noise survey report in Appendix 9.D.

The Project site is located in a mixed industrial and rural area with no residents within 0.5 mile of the site and approximately 30 residences within a 1-mile radius of the site. The noise sources in the area include wind, birds, insects, distant industrial facilities, boat traffic, and

vehicular traffic on local roads. Meteorological conditions during the measurements included clear to partly cloudy skies, northwest winds of 3 to 7 miles per hour and temperatures from 66 to 93 degrees Fahrenheit. The nearest NSA (NSA #1) is a residence located about 3,820 feet south of the center of the proposed LNG liquefaction trains.

Sound level measurements were collected at the nearest NSAs to the Project site identified as follows:

- NSA #1 - West end of Private Drive off Big Lake Road, north of Airhart Road
- NSA #2 - East end of Private Drive off Big Lake Road, north of Airhart Road
- NSA #3 - 8366 Joe Ledoux Road

Figure 9.3-1 illustrates the Project site and NSA locations. Figures 9.3-2 through 9.3-4 show the hourly average L_{eq} sound level at NSA #1, #2, and #3 respectively.

A summary of the existing noise levels is provided in Table 9.3-1.

Table 9.3-1 Existing Noise Level Summary for the Project Site

NSA	Distance from NSA (feet)	Direction from NSA	Average Daytime L_{eq} (dBA)	Average Nighttime L_{eq}(dBA)	Calculated Ldn (dBA)
#1	3,820	North	46.9	43.8	50.8
#2	4,485	Northwest	48.7	44.8	52.0
#3	7,075	Northwest	43.6	40.2	47.3

Document Path: C:\VPN_WORK\active_projects\Magnolia_LNG_2014\maps\mxds\rr9\Noise Sensitive Area (NSA) Locations.mxd



Figure 9.3-1
Noise Sensitive Area (NSA) Locations Nearest to the Magnolia LNG Project Site

Magnolia LNG
Calcasieu Parish, Louisiana

Legend

Proposed LNG Facility Boundary

NSA Location

N
W E
S

0 1,000 2,000 Feet

1:12,000

MAGNOLIA LNG

Source- ESRI 2011-2012
Image Date- 08/27/2013
Date: 4/15/2014

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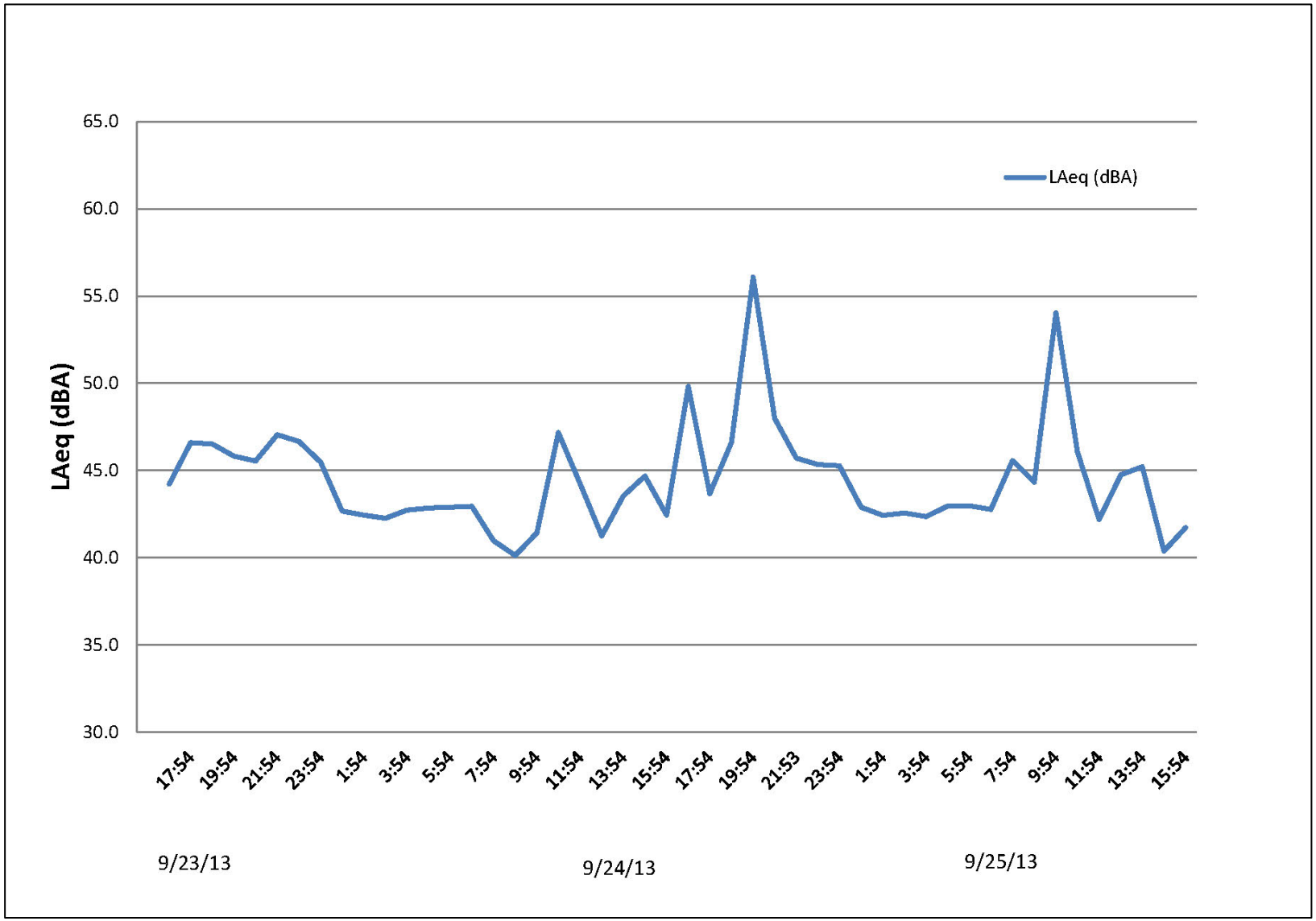


Figure 9.3-2 Hourly LAeq Noise Level (dBA) – Receptor 1

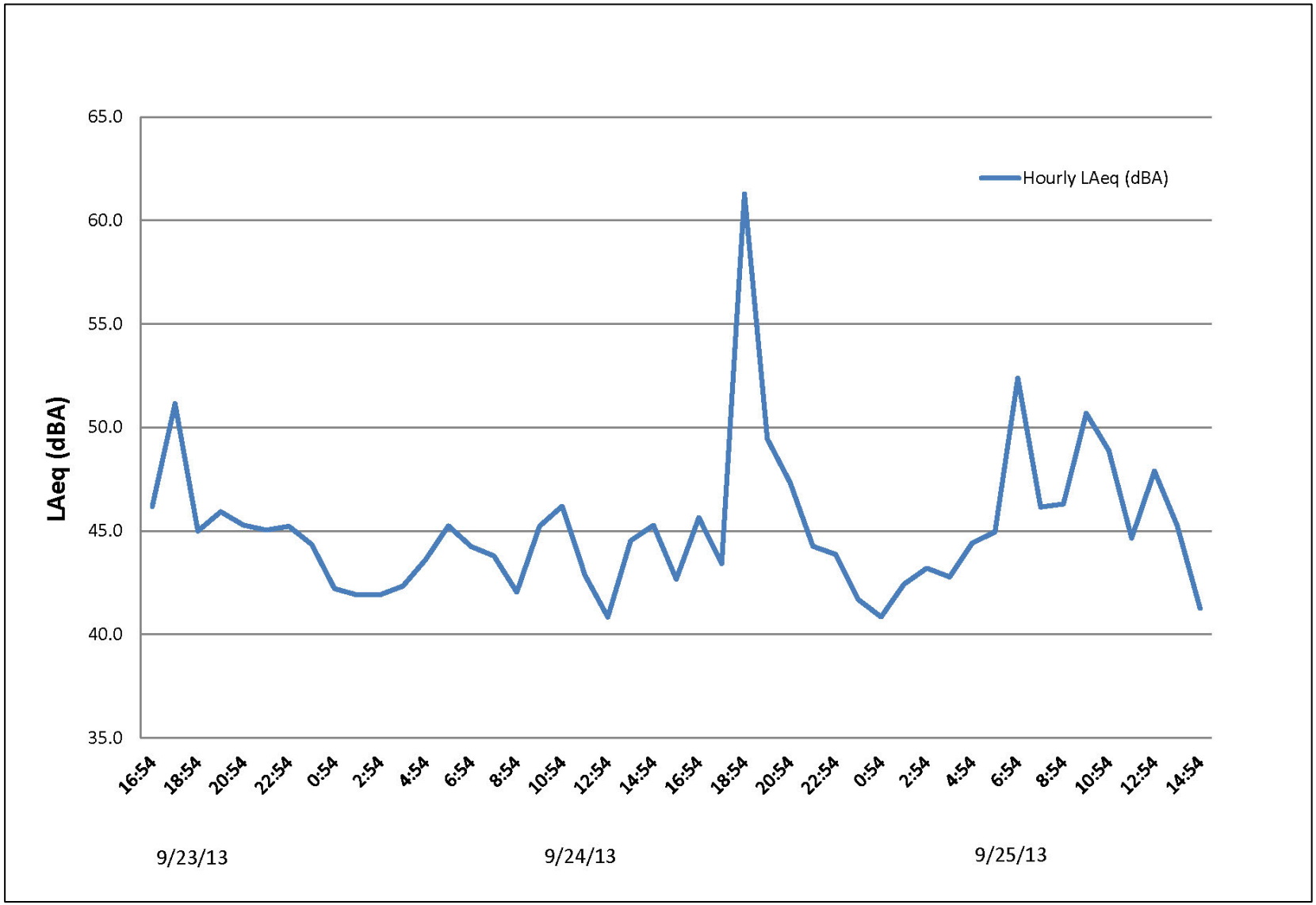


Figure 9.3-3 Hourly LAeq Noise Level (dBA) – Receptor 2

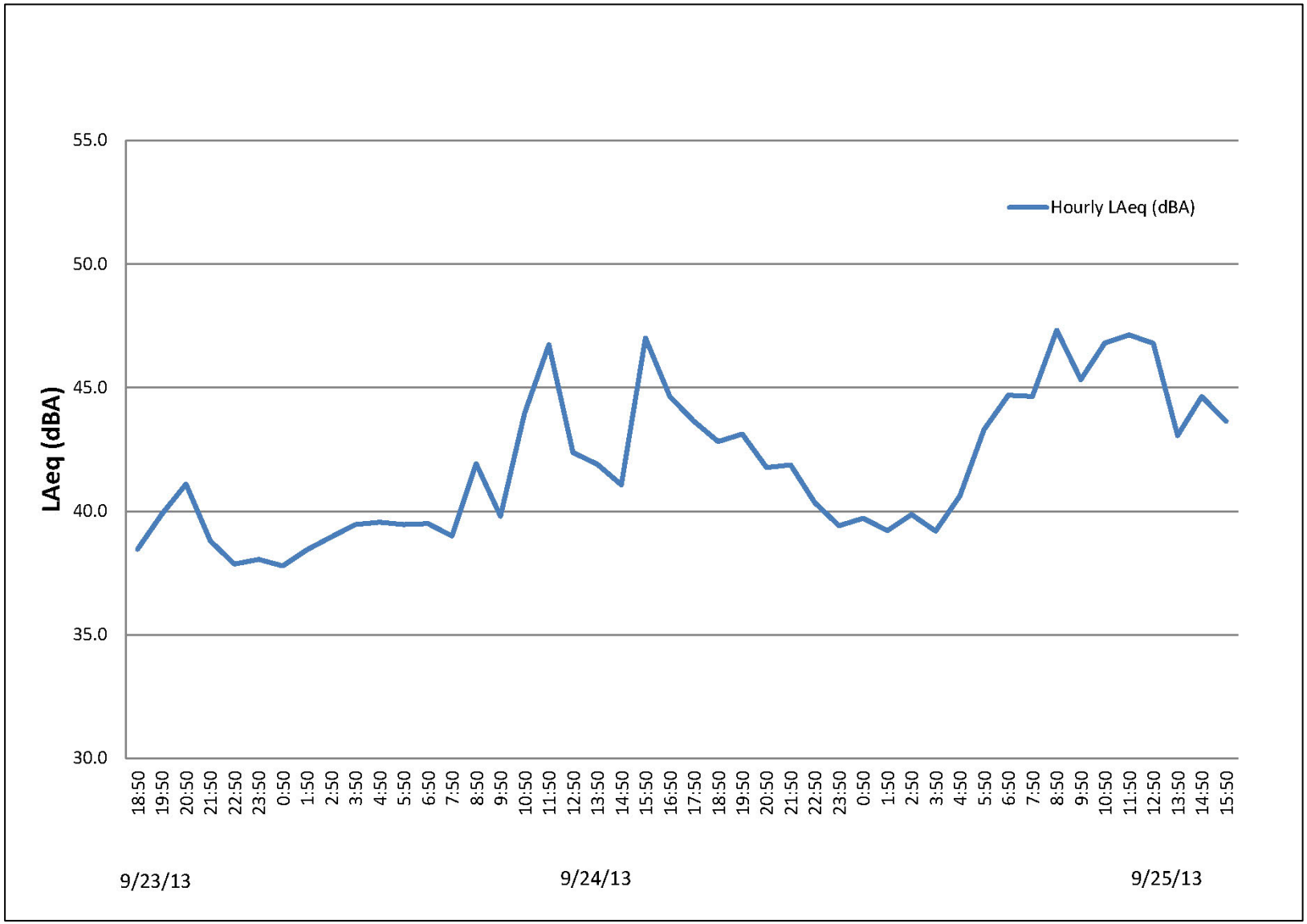


Figure 9.3-4 Hourly LAeq Noise Level (dBA) – Receptor 3

9.3.3 Acoustical Analyses

9.3.3.1 Construction Noise

Construction activities at the Project site would involve clearing and grading, placement of fill, installation of foundations for the planned Project facilities, other equipment settings, ancillary equipment, piping, and structures, pile-driving, and dredging. Construction is projected to begin in mid-2015 (July 1, 2015) with proposed facilities placed into service by June 2018. Construction of the Project would cause temporary increases in ambient noise levels in the immediate vicinity of the construction sites. Construction operating hours would be from 7:00 a.m. to 7:00 p.m., Monday through Saturday.

Noise levels resulting from construction equipment are dependent on several factors including the number and type of equipment operating, the level of operation, and the distance between sources and receptors. The loudest equipment during construction would contribute to a composite average or equivalent site noise level. Heavy construction equipment typically generates noise levels up to approximately 95 dBA at 50 feet. As part of this analysis, acoustic noise modeling was conducted to estimate the construction noise levels at the nearest NSAs around the Project site. Tables 9.3-2 and 9.3-3 present the expected Project construction equipment types and quantities for site preparation and facility construction that were used in the noise calculations and the estimated noise levels at various distances. Noise emission levels were gathered from equipment manufacturers and government agency references. The usage factors were selected from the Federal Highway Administration Highway Construction Noise Handbook (U.S. Department of Transportation 2006). Usage factors are used to account for the intermittent use of construction equipment throughout the course of a normal workday.

Table 9.3-2 Site Preparation Construction Noise Levels at Various Distances

Construction Equipment	Quantity	Usage Factor %	L_{max} SPL @ 50 Feet (dBA)	Distance in Feet/SPL[1] (dBA)				
				50 (adjusted)[2]	250	500	1000	1500
Pickup Truck	3	40	75	76	62	56	50	46
Flatbed Truck	1	40	74	70	56	50	44	40
Dump Truck	8	40	76	81	67	61	55	52
Fuel Truck	1	40	76	72	58	52	46	42
Dozer	6	40	82	86	72	66	60	56
Backhoe	2	40	78	77	63	57	51	47
Trackhoe	3	40	78	79	65	59	53	49
Grader	2	40	85	84	70	64	58	54
Sheepsfoot Roller	4	20	80	79	65	59	53	49
Drum Roller	4	20	80	79	65	59	53	49
			Composite Noise Level	**90**	**76**	**70**	**64**	**61**

[1]SPL = Sound Pressure Level
[2]Adjusted to usage factor and equipment quantity
Source: U.S. Department of Transportation August 2006.

Table 9.3-3 Facility Construction Noise Levels at Various Distances

Construction Equipment	Quantity	Usage Factor %	L_{max} SPL @ 50 Feet (dBA)	Distance in Feet/SPL[1] (dBA)				
				50 (adjusted)[2]	250	500	1000	1500
Pickup Truck	2	40	75	74	60	54	48	44
Flatbed Truck	2	40	74	73	59	53	47	43
Cement Truck	2	40	79	78	64	58	52	48
Cement Pump Truck	2	20	81	77	63	57	51	47
Fork Truck	2	40	84	83	69	63	57	53
Manlift	2	20	75	71	57	51	45	41
Backhoe	2	40	78	77	63	57	51	47
Trackhoe	2	40	78	77	63	57	51	47
Picker	6	16	81	81	67	61	55	51
Welder	4	40	74	76	62	56	50	46
Compressor	2	40	78	77	63	57	51	47
Compactor	2	20	83	79	65	59	53	49
		Composite Noise Level		**89**	**75**	**69**	**63**	**59**

[1]SPL = Sound Pressure Level
[2]Adjusted to usage factor and equipment quantity
Source: U.S. Department of Transportation August 2006.

Since the nearest noise-sensitive receptor property to the Project is approximately 3,820 feet from the approximate center of the construction site, the estimated noise level due to Project construction at that distance would be 52 dBA during site preparation and 51 dBA during facility construction. These levels might occur temporarily over the course of the Project construction and would be audible at times at the nearest NSAs.

Pile Driving

The steel sheet bulkhead for the LNG loading platform would be installed by use of vibratory hammer or a hydraulic pile driver. The five monopile steel breasting dolphin foundations also would be installed using a hydraulic pile driver. Likewise, the 24 cylindrical concrete pilings driven into the seabed to support the LNG loading platform would be installed using a hydraulic pile driver. The proposed foundation arrangement for each LNG storage tank would include the use of 1,508 pre-stressed concrete piles of 2 feet by 2 feet in cross-section by 70 feet in length. The two LNG storage tanks would have a combined total of 3,016 piles. The piles would be driven by hydraulic hammer as is typical of these installations. The installation would occur over a multiple month period (refer to RR1, "General Project Description," Appendix 1.C) due to the number of pilings required (refer to RR 13, "Engineering and Design Material") for the proposed arrangement and piling specifications and numbers). Figure 9.3-5 shows the approximate location of the pile-driving activities in relation to the nearest NSAs.

The expected L_{max} sound level for a pile driver operation is 101 dBA. The sound level due to the pile driver operation at the NSAs can be calculated based on the formula for geometric spreading of sound energy over distance. Assuming three simultaneous pile-driving operations at the approximate center of the Project construction area, the predicted sound level due to pile-driving would be about L_{max} 68 dBA at the nearest NSA (see Table 9.3-4). Three pile-drivers would likely be in operation most of the time; however, a fourth pile-driver may be brought on-site depending on possible schedule delays and weather. With four simultaneous pile-driving operations at the approximate center of the Project construction area, the predicted sound level due to pile-driving would be about L_{max} 69 dBA at the nearest NSA.

This is a conservative estimate in that no reductions were taken for the effect of ground or atmospheric absorption. The pile-driving operation would be audible at the nearest NSAs but would be temporary in duration.

Table 9.3-4 Pile-Driving SPLs at NSAs

Number of Simultaneous Pile Driving Operations	NSA	Distance from NSA to Approximate Center of Construction Area (feet)	Direction from NSA	SPL Three Hydraulic Pile Drivers (L_{max}) at 50 feet	L_{max} SPL at NSAs (dBA)
3	#1	3,820	North	106	68
3	#2	4,485	Northwest	106	67
3	#3	7,075	Northwest	106	63
4	#1	3,820	North	107	69
4	#2	4,485	Northwest	107	68
4	#3	7,075	Northwest	107	64

Table 9.3-5 presents the estimated duration for the pile-driving activities based on three pile-driving rigs in some cases operating simultaneously and each rig being able to drive 17 piles per day.

Table 9.3-5 Pile-Driving Duration

Pile-Driving Activity	Duration (months)
Sheet steel bulkhead	3.5
Monopile steel breasting dolphin foundations	2
Cylindrical concrete pilings	3.5
LNG storage tanks (2)	3

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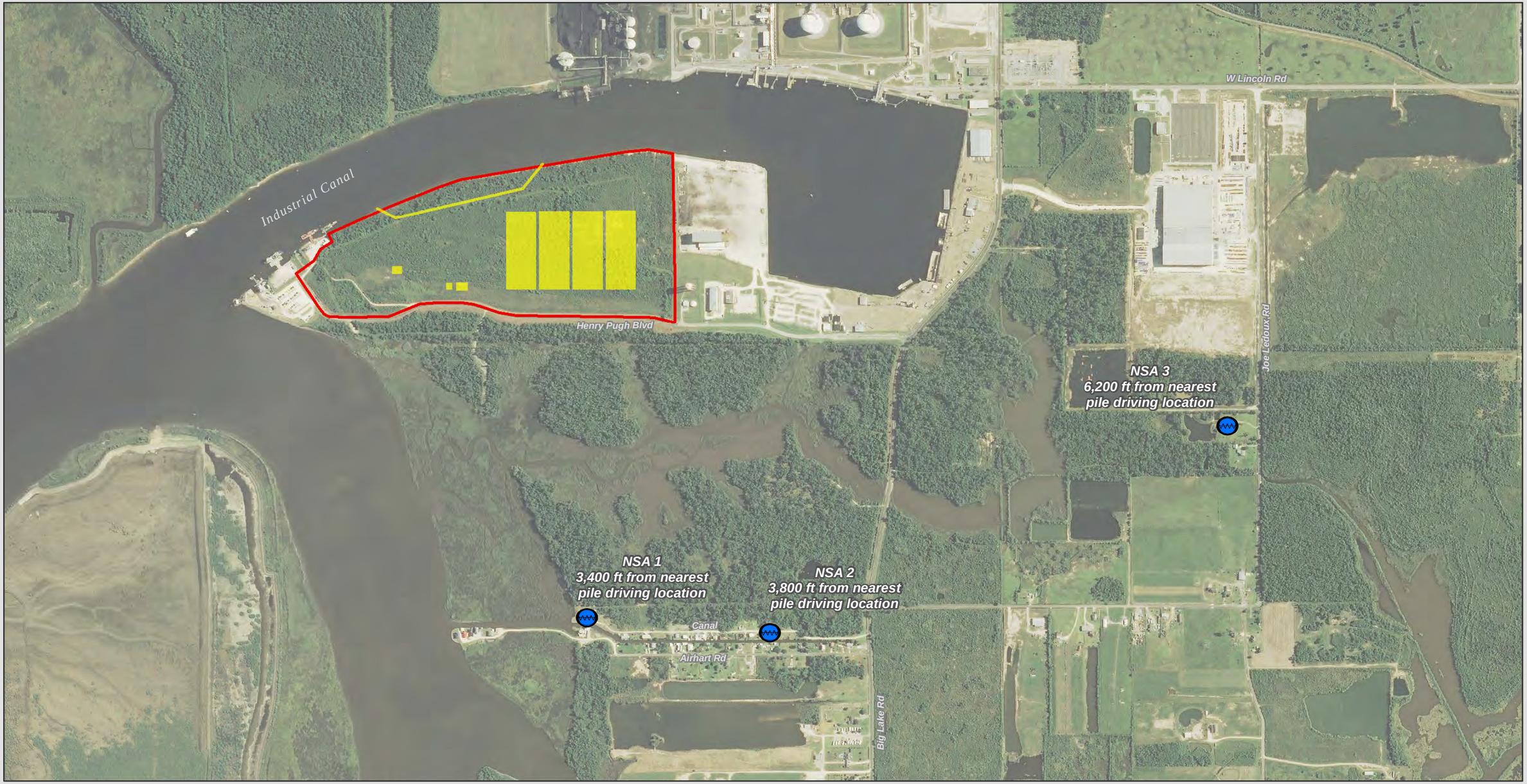


Figure 9.3-5
Approximate Location of Pile-Driving Activities in Relation to Noise Sensitive Area (NSA) Locations

Magnolia LNG
Calcasieu Parish, Louisiana

Legend

- Proposed LNG Facility Boundary
- NSA Location
- Pile-Driving Activity Area

N W E S

0 1,000 2,000 Feet

1:12,000

MAGNOLIA LNG

Source- ESRI 2012, NAIP 2013
Image Date- 08/27/2013
Date: 4/28/2014

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Dredging

The LNG vessel loading facility would be recessed into the northern boundary of the site. To create the recessed berthing and waterway access area, a combination of onshore excavation and dredging would be required at the site (see Figure 9.3-6 for dredging location). Dredging would be accomplished by use of a hydraulic cutterhead suction dredge. Generally, hydraulic dredges generate noise at around 60 to 80 dBA at 50 feet, depending on size of dredge, engine, and other characteristics. Table 9.3-6 presents the noise levels at the nearby NSAs based on an upper dredging noise level of 80 dBA at 50 feet.

Table 9.3-6 Dredging SPLs at NSAs

NSA	Distance from NSA (feet)	Direction from NSA	Hydraulic Dredge (L_{eq}) at 50 feet	SPL at NSAs (dBA)
#1	4,400	North	80	41
#2	5,100	Northwest	80	40
#3	7,300	Northwest	80	37

Vibration

Operation of construction equipment causes ground vibrations that spread through the ground and diminish in strength with distance. According to the Federal Transit Administration (FTA), pile-driving would be the greatest source of vibration during the Project construction. The vibration level at a receptor location can be calculated based on the distance from the site using the following equation:

$$L_v(D) = L_v(25\ ft) - 20log(D/25)$$

Where:

D = distance (feet)

L_v = vibration level (VdB)

Using this equation with a level of 112 VdB for a single pile-driver at 25 feet (FTA 2006), the vibration level at the nearest NSA (NSA #1) would be 68 VdB. This level is below the FTA impact criteria for general assessment for ground-borne vibration of 72 VdB for a residence. Although three and possibly 4 pile drivers could be operating simultaneously, it would be unlikely that the vibrational waves generated by the pile drivers would coincide due to different equipment locations and likely non-coincident driver strike times.

9.3.3.2 Operational Noise

Operation of the proposed Project may result in long-term increases in noise levels in the vicinity of the Project. Noise would generally be produced on a continuous basis by the Project equipment including compressors, power generation units, pumps, and cooling fans.

To identify potential noise impacts resulting from the operation of the Project, acoustic modeling was conducted and the modeling results were compared with the FERC limit of Ldn 55 dBA. Acoustic noise modeling of the major Project sources was conducted using the CadnaA acoustic model version 3.7.124 developed by Datakustik GmbH.

Primary noise-producing equipment to be included in the Project, along with corresponding estimated noise emission data and noise control equipment reduction values were derived from equipment manufacturer's data sheets and measurements at other LNG facilities. The model simulates the outdoor three-dimensional propagation of sound from each noise source and accounts for sound wave divergence, atmospheric and ground sound absorption, and sound attenuation due to interceding barriers and topography based on the International Standard ISO9613-2 (ISO 1996). Standard conditions of 50 degrees Fahrenheit and 70 percent relative humidity were assumed. Ground absorption was set to 1. A database was developed that specified the location and sound power levels of each noise source. A receptor grid was specified that covered the entire area of interest. The model calculated the overall A-weighted sound pressure levels (SPLs) within the receptor grid based on the sound level contribution of each noise source. The model receptors included the three identified NSAs.

Table 9.3-7 presents the unmitigated sound levels for the major noise-producing equipment associated with the Project. Figure 9.3-7 illustrates the locations of the major noise-producing equipment. This figure shows one of the four LNG trains; locations in the other trains would be similar. Table 9.3-8 presents the noise reduction values for the potential noise controls that were included in the model.

The results of the noise modeling for the Project operation with the noise control measures from Table 9.3-8 included are presented in Table 9.3-9. The results indicate that sound levels associated with the operation of the Project at the nearest NSA would be 52.1 dBA Ldn, which is below the FERC limit of Ldn 55 dBA. Table 9.3-9 also presents the expected increase in Ldn above the existing Ldn. The expected increases in noise levels at the NSAs are shown to be small, ranging from 0 dBA to 1.3 dBA. Increases this small are not considered to be perceptible.

Flaring events would occur infrequently, mainly during startup or shutdown of the proposed Magnolia LNG facility. Typically gas is flared for one to two hours during these events. This may occur at frequencies of the order of three to four times a year. The flaring creates noise with a low-pitched 'roaring' character. The peak sound pressure level for a high pressure flare at 1,500 feet is 80 dBA (Baukal 2001). The estimated SPL at NSA # 1 (the nearest NSA at a distance of 3,820 feet from the Project site) during a flaring event would be 72 dBA.

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Figure 9.3-6
Approximate Dredging Location in Relation to Noise Sensitive Area (NSA) Locations

Magnolia LNG
Calcasieu Parish, Louisiana

Legend

Proposed LNG Facility Boundary
NSA Location
Dredge Area

N
W E
S

0 1,000 2,000 Feet
1:12,000

MAGNOLIA LNG

Source- ESRI 2012, NAIP 2013
Image Date- 08/27/2013
Date: 4/28/2014

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Table 9.3-7 Unmitigated Sound Levels for Major Noise-Producing Equipment

Equipment	Quantitiy Modeled	Weight	Sound Power/Octave Spectrum Band (Hz) 31.5	63	125	250	500	1000	2000	4000	8000	dBA
LM2500+Gas Turbine Compressor/Generator Package	8	Lw	77	86	99	97	96	95	99	100	96	105.1
LM2500+Gas Turbine Compressor Exhaust	8	Lw	91	107	119	126	130	129	128	129	120	135.1
Solution Cooler Fan Unit	128	LwA		81	91	95	98	97	95	92	82	103.2
Cooler Fan	40	Lw	69	79	85	89	89	89	88	87	79	94.5
Steam Generator	8	Lw		77	88	92	97	100	99	98	92	105.1
Amine Charge Pumps	8	LwA		67	78	87	93	99	97	93	85	102.5
Miscellaneous Pumps	54	Lw	91	93	95	95	95	95	95	92	85	100.6
Instrument Air Package	12	Lw	91	96	93	98	95	91	88	90	89	98.1
Boil-off Gas Compressor	5	Lw	113	114	118	116	105	106	101	99	94	111.9
Boil-off Gas Compressor Motor	5	Lw	95	95	98	100	103	103	102	97	89	107.7
Ammonia Compressor	8	LwA	-	-	-	-	-	-	-	-	-	85
Liquefaction Train Piping	4	Lw	16	29	39	83	112	115	103	92	73	116.2

Table 9.3-8 Noise Control Reduction Values

Noise Source	Noise Control	Noise Reduction/Octave Spectrum Band (Hz) 31.5	63	125	250	500	1000	2000	4000	8000
Gas Turbine Exhaust	Gas Turbine Exhaust Silencer	2	5	12	24	34	40	39	31	11
BOG Compressors	BOG Building Enclosure	8	12	11	16	26	34	41	44	46
Liquefaction Train Pipe	Pipe Lagging	0	0	0	2	11	20	29	36	42

Table 9.3-9 Summary of Project Operation Noise Levels at NSAs and Expected Increase in Ldn Above the Existing Ldn

NSA	Distance from NSA (feet)	Direction from NSA	Existing Ambient Ldn (dBA)	Project Contribution Ldn (dBA)	Combined Ldn (dBA)	Expected Increase
#1	3,820	North	50.8	46.4	52.1	1.3
#2	4,485	Northwest	52.0	44.5	52.7	0.7
#3	7,075	Northwest	47.3	24.4	47.3	0.0

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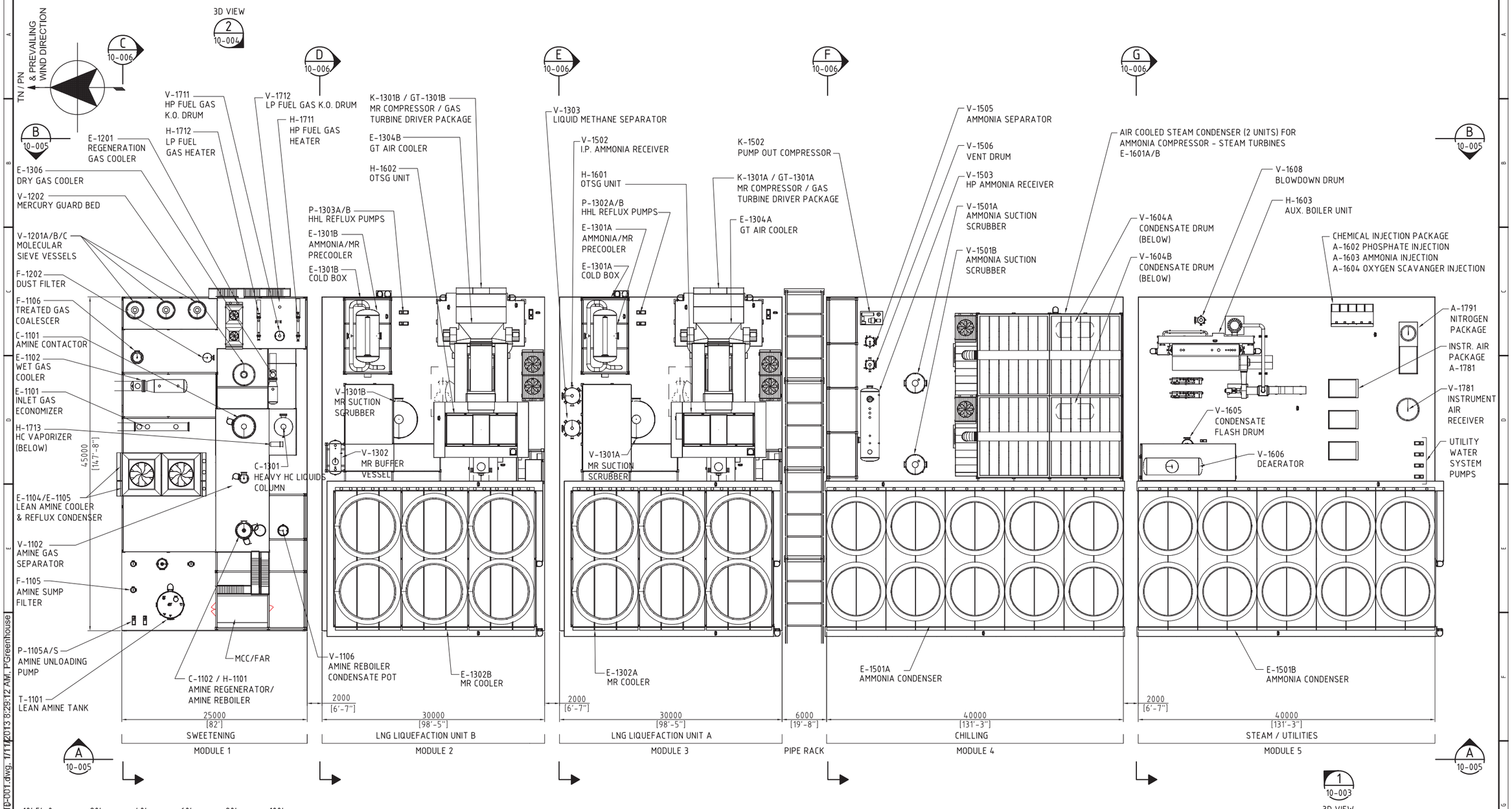


Figure 9.3-7 Locations of Major Noise-Producing Equipment (1 of 4 Trains)

PLAN

TRAIN 1

NOTE : THIS DRAWING REPRESENTS TRAIN 1 ONLY

NOTE:

1. EQUIPMENT LAYOUT AND SIZING IS BASED ON PRELIMINARY VENDOR INFORMATION.
2. DIMENSIONS SHOWN ARE APPROXIMATE AND ONLY FOR INDICATIVE REFERENCE.

INFORMATION ONLY
NOT TO BE USED
FOR CONSTRUCTION

DRAWING No	REFERENCE DRAWINGS	REV	DATE	REVISION DESCRIPTION	DRAWN	CHECKED	DESIGNED	APPROVED
		B	7 NOV'13	UPDATE	PNG	LC	LC	PB
		A	08 OCT'13	ISSUED FOR INFORMATION	PNG			

MAGNOLIA LNG

DRAWN:	PNG	DATE:	08 OCT'13
CHECKED:	LC	DATE:	7 NOV'13
ENGINEER:	LC	DATE:	7 NOV'13
APPROVED:	PB	DATE:	7 NOV'13
CLIENT:		DATE:	

MAGNOLIA LNG PROJECT
LIQUEFACTION TRAIN No 1
EQUIPMENT / MODULE ARRANGEMENT
PLAN

SCALE: AS SHOWN | DRG No MG-DM-10-001 | REV B

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9.3.4 Mitigation

9.3.4.1 Project Construction

The following mitigation measures may be implemented as needed to control construction noise:

- Locate stationary construction equipment away from noise receptors where feasible.
- Turn off idling equipment when not in use.
- Install temporary acoustic barriers around stationary construction noise sources, as feasible.
- Perform construction during daytime hours when there is less sensitivity to sound.
- Ensure that all equipment has sound control devices no less effective than those provided by the manufacturer.

9.3.4.2 Project Operation

Mitigation measures included in the acoustic model for the operation of the Project are gas turbine exhaust silencers, the boil-off gas compressor building enclosure, and pipe lagging on the liquefaction train piping (see Table 9.3-8).

9.4 CUMULATIVE IMPACTS

As discussed in RR 1, "General Project Description" (see Section 1.9, "Cumulative Impact Analysis,"), cumulative impacts are the collective result of the incremental impacts of an action that, when added to the impacts of other past, present, and reasonably foreseeable future actions, would affect the same resources, regardless of what agency or person undertakes those actions (40 CFR 1508.7). Procedures for developing the cumulative project inventory are discussed in RR 1, Section 1.9.

9.4.1 Air Quality

For air quality, a subset of the potential cumulative projects identified in RR 1, Table 1.9-1 would have the potential to produce a cumulative air pollutant impact with the proposed Project. The potential for cumulative impacts is based on the type of project, its stage of development and the likely potential for significant ongoing air pollutant emissions whose impact may overlap with the Project. Planned projects (i.e., projects that have documented and submitted their emissions for public review) up to 10 miles away from the Project would have the potential for a cumulative impact on air quality; facilities beyond 10 miles may have a potential for additional cumulative impacts depending on their potential emissions. Projects within 10 miles of the proposed Project site include:

- Trunkline LNG
- G2X Energy
- W.R. Grace
- Cameron LNG
- Lake Charles Cogeneration
- Westlake Chemical
- Sasol North America

Cumulative impacts will be assessed with dispersion modeling through the air permitting process. Modeling will be required to address Project-only impacts in comparison to the SILs contained in NSR PSD impact assessment requirements. Modeled air pollutant concentrations above the respective SILs outside of the Project site's fence line would indicate a potential for cumulative impact with other facilities. Based on the distance beyond the fence line where Project-only modeled concentrations decrease below the SIL, a radius of influence is established. A cumulative source emission inventory will then be developed for major emission sources within the radius of influence and included in a cumulative modeling assessment.

Cumulative impacts on regional ozone levels would also be addressed through a photochemical modeling study, if required by the LDEQ.

If modeling for permit application support does not indicate modeled concentrations beyond the fence line are above respective SILs, Magnolia will perform a cumulative modeling assessment focused on nearby facilities to address the FERC's concern regarding cumulative impacts.

Generally, construction projects with multiple-year overlapping construction schedules or single-year projects that occur in the same year could contribute to a cumulative impact. Construction emissions typically consist of equipment and vehicle exhaust emissions and fugitive dust. Construction cumulative impacts are highly variable and difficult to predict due to several factors that vary spatially and temporally for the group of projects contributing to a potential cumulative effect. These factors include timing of the construction projects, intensity and type of construction activity underway at any given time, quantity and size of emission producing equipment in operation, distance separating the projects and factors that affect fugitive dust emissions such as soil silt content, quantity of dust-producing material being handled, and dry or windy conditions. When construction is complete for a project, it would no longer contribute to construction cumulative effects with other projects.

Potential projects in proximity to the Project include three proposed projects within 0.5 mile of the Project site. These projects are G2X Energy, Trunkline LNG, and the Lake Charles Fisheries Research Center. Two of these projects, G2X Energy and Trunkline LNG, anticipate a construction period beginning in 2014 and ending in 2017 (see Table 1.9-1 in RR 1, "General Project Description"). This construction period would overlap with the Project's construction period of mid 2015 through 2017. The construction of the Lake Charles Fisheries Research Center would not overlap with the construction of the Magnolia Project, and the construction

schedule will not be established until after the facility is designed; therefore, it is not possible to speculate on its potential to contribute to a cumulative impact.

Cumulative impacts due to the combination of construction emissions from the Project with G2X Energy and Trunkline LNG are possible. Preliminary construction activity information and construction emission estimates are available for Trunkline LNG from their FERC RR 9, but are not available for G2X Energy (G2X is not subject to FERC jurisdiction or any other requirement to estimate construction emissions). The potential cumulative impact with the Project's construction emissions shown in Table 9.2-4 would, therefore, be limited. The potential for cumulative construction emissions impacts would be greatest during site preparation when fugitive dust production would likely be at its peak due to excavation, grading, transport of soil and gravel and similar types of basic site preparation activities. If G2X Energy and Trunkline LNG begin construction in 2014 as shown in Table 1.9-1 of RR 1, the first phase of both projects would likely be site clearing and preparation activity in 2014. Assuming that these two projects have a site preparation phase similar in duration to the Project's, their peak fugitive dust production period would be completed prior to the start of the Project's site preparation phase in the latter half of 2015, minimizing the potential for a fugitive dust cumulative impact. Mitigation measures are also available to minimize fugitive dust such as applying water or other dust control chemicals to control dust, or limiting activity during windy conditions. Mitigation would need to be coordinated amongst all potential contributors to a fugitive dust cumulative impact.

Emission of criteria pollutants from combustion of fuel in equipment and vehicle exhaust could also contribute to a cumulative impact. These emissions would be minimized by typical control techniques such as use of low-sulfur diesel fuel, proper operation of equipment and reduction of daily emissions by using equipment during daylight hours only as much as possible.

9.4.2 Climate Change

National and international organizations have identified that GHGs have been increasing in concentration in the atmosphere since the late 1700s and identify them as the primary factor affecting climate change. The primary source of these gases is combustion of fossil fuels, with coal combustion emitting the highest amount of GHG per energy unit. Deforestation and agriculture also contribute to the rise in GHG concentration in the atmosphere. Climate change is inherently a cumulative issue since impacts such as sea level rise and increasing average air temperatures are believed to be the result of cumulative emissions from worldwide sources. However, at the project level, there is no available method to assess a project's individual GHG emission impact on changes in climate.

GHG emissions from the construction and operation of the proposed Project are discussed in Sections 9.2.5 and 9.2.6, respectively. Magnolia is incorporating highly efficient processes to minimize to the extent feasible emissions of GHGs. For circulating the MR, the Project would use aeroderivative gas turbines rather than larger, less-efficient frame gas turbines. CHP technology would be employed to recover waste heat from each gas turbine exhaust in order to generate high pressure (HP) steam, which is then used to drive the auxiliary ammonia-based cooling system and other various processes at the facility, thereby reducing the need for

supplemental fossil fuel based energy. In addition, the auxiliary ammonia-based cooling system would serve to increase the output of the gas turbines and also the fuel efficiency of the gas turbines by chilling the inlet air to maintain a stable inlet air temperature, allowing the gas turbine combustion process to be optimized for efficiency. The ammonia cooling system would also be used to pre-cool the feed gas and the MR prior to entering the cold box. This would increase efficiency of the cold box by lessening the temperature difference between the two gas streams. Therefore, as the MR exits the cold box, it would return to the main MR compressor at a lower temperature due to the pre-cooling, significantly improving MR compressor performance, reducing energy demand and emissions. As noted in Section 9.1, "Project Description," these features would increase the efficiency of the Project by approximately 30 percent compared to conventional liquefaction processes, and thus would minimize GHG emissions.

9.4.3 Noise

Noise decreases logarithmically with increasing distance from a noise source, therefore cumulative operational noise impacts would only occur with other facilities in immediate proximity to the Project. Two facilities, Trunkline LNG and G2X Energy, are approximately 0.5 mile from the Project site and could potentially create a cumulative noise impact. However, as shown in Table 9.3-9, noise impacts due to the Project at noise sensitive locations 3,280 feet from the Project site and beyond would be less than the FERC 55dBA threshold. Considering that the FERC 55dBA noise thresholds will also apply to the Trunkline LNG facility, cumulative noise impacts are expected to remain below 55dBA for cumulative impacts from these two facilities. The G2X Energy facility is not regulated by FERC and thus not subject to the FERC noise threshold; however, the G2X facility is located 0.5 mile north of the Project and would not be expected to contribute significantly to the noise levels at the Project NSAs. The G2X facility would be subject to Calcasieu Parish noise regulations found in the Calcasieu Parish Police Jury Code of Ordinances, Chapter 18, Article VIII.

Cumulative construction noise impacts depend on the overall timing of construction for each project and the type of daily construction activities occurring at each facility. Magnolia will minimize its construction noise using mitigation described in Section 9.3.4.1, "Project Construction," to limit cumulative construction noise impacts to the extent feasible for its own construction procedures.

9.5 REFERENCES

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Construction Emissions

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Table 9.A.1 - Construction Emission Summary

2015 Emissions (tons)

Construction Phase	VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
Phase I Site Prep	0.64	0.73	0.71	3.11	6.43	1817	0.33
Phase II LNG Tanks	1.04	1.01	0.98	13.45	10.07	2599	0.47
Phase III BOP	0.54	0.55	0.53	5.16	5.29	1435	0.26
Phase IV Architectural	0.00	0.00	0.00	0.00	0.00	0	0.00
Phase V Marine	0.38	0.40	0.40	2.97	11.52	954	1.08
Phase VI Misc	0.09	0.09	0.09	2.40	0.56	225	0.04
Fugitive Dust	n/a	14.87	1.49	n/a	n/a	n/a	n/a
Worker Commuting	0.02	0.02	0.01	1.63	0.12	238	0.01
Total	2.72	17.66	4.20	28.73	33.99	7,269	2.18

2016 Emissions (tons)

Construction Phase	VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
Phase I Site Prep	0.00	0.00	0.00	0.00	0.00	0	0.00
Phase II LNG Tanks	4.08	2.94	2.85	92.92	24.49	8739	1.52
Phase III BOP	0.43	0.35	0.34	5.78	2.89	1010	0.17
Phase IV Architectural	1.39	0.25	0.24	49.19	3.66	856	0.15
Phase V Marine	1.21	0.85	0.83	30.93	12.04	2523	1.04
Phase VI Misc	0.12	0.14	0.13	0.48	0.83	427	0.07
Fugitive Dust	n/a	14.35	1.43	n/a	n/a	n/a	n/a
Tug Transport	0.54	0.60	0.60	4.96	25.80	1385	2.58
Worker Commuting	0.04	0.03	0.01	2.80	0.21	408	0.01
Total	7.80	19.50	6.43	187.06	69.93	15,349	5.54

2017 Emissions (tons)

Construction Phase	VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
Phase I Site Prep	0.00	0.00	0.00	0.00	0.00	0	0.00
Phase II LNG Tanks	2.85	1.51	1.47	88.41	11.73	4022	0.70
Phase III BOP	0.21	0.13	0.13	4.63	0.85	372	0.06
Phase IV Architectural	1.18	0.16	0.15	45.74	2.59	654	0.12
Phase V Marine	0.40	0.25	0.24	11.58	1.66	858	0.14
Phase VI Misc	0.11	0.12	0.12	0.40	0.62	396	0.06
Fugitive Dust	n/a	14.26	1.43	n/a	n/a	n/a	n/a
Worker Commuting	0.04	0.03	0.01	2.80	0.21	408	0.01
Total	4.79	16.45	3.54	153.56	17.67	6,711	1.09

Summary - all years	**15.31**	**53.61**	**14.17**	**369.35**	**121.59**	**29,329**	**8.82**

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Table 9.A.2 - Phase I Site Preparation Construction Emissions - Year 2015

Magnolia LNG Project

Construction Equipment Utilization Matrix

Site Preparation: Earth Moving/Road Work

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year					Equipment Months	NONROAD Emission Factor (gram/hr)						
						6	7	8	9	10		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																		
PICK-UP TRUCK or VAN newer then 2010	10%	325.5	GMC 1500	250	Gas	3	3	3	3	3	15	21.36	21.66	21.01	39.51	163.59	77312	12.52
A - ROLLING EQUIP																		
2-T FLATBED TRUCK	50%	542.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	5	21.36	21.66	21.01	39.51	163.59	77312	12.52
DUMP TRUCK 6CY	100%	4340	Mack Truck Granite Series	415	Diesel	4	4	4	4	4	20	38.53	45.09	43.74	157.72	403.14	132878	23.48
DUMP TRUCK 14CY	100%	4340	Mack Truck Granite Series	415	Diesel	4	4	4	4	4	20	38.53	45.09	43.74	157.72	403.14	132878	23.48
FUEL TRUCK	30%	325.5	Chevrolet C3500	397	Diesel	1	1	1	1	1	5	38.53	45.09	43.74	157.72	403.14	132878	23.48
MECH TRUCK	2%	21.7	GMC 1500	250	Gas	1	1	1	1	1	5	21.36	21.66	21.01	39.51	163.59	77312	12.52
B - EARTH MOVING																		
450 CASE DOZER	100%	6510	Case 650L	74	Diesel	6	6	6	6	6	30	7.78	9.52	9.24	71.49	114.79	20370	3.95
580 BACKHOE	100%	2170	Case 580N	78	Diesel	2	2	2	2	2	10	17.81	16.23	15.74	104.35	85.04	12687	2.55
225 TRACK HOE	100%	3255	Case CX210C	160	Diesel	3	3	3	3	3	15	17.72	13.94	13.52	65.90	110.85	15827	3.18
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	217	Case 885B	214	Diesel	2	2	2	2	2	10	24.38	26.28	25.49	84.59	248.66	73154	13.19
SHEEPSFOOT	50%	2170	Caterpillar CP54B	131	Diesel	4	4	4	4	4	20	17.23	21.63	20.98	74.95	185.35	41820	8.01
DRUM ROLLER	50%	2170	Caterpiller CS44	100	Diesel	4	4	4	4	4	20	13.31	20.02	19.42	129.62	141.05	29773	5.70

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2015 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year					Equipment Months	Annual Emission (ton)						
						6	7	8	9	10		VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
SK TRUCKS & CARS																		
PICK-UP TRUCK or VAN newer then 2010	10%	325.5	GMC 1500	250	Gas	3	3	3	3	3	15	0.01	0.01	0.01	0.01	0.06	28	0.00
A - ROLLING EQUIP																		
2-T FLATBED TRUCK	50%	542.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	5	0.01	0.01	0.01	0.02	0.10	46	0.01
DUMP TRUCK 6CY	100%	4340	Mack Truck Granite Series	415	Diesel	4	4	4	4	4	20	0.18	0.22	0.21	0.75	1.93	636	0.11
DUMP TRUCK 14CY	100%	4340	Mack Truck Granite Series	415	Diesel	4	4	4	4	4	20	0.18	0.22	0.21	0.75	1.93	636	0.11
FUEL TRUCK	30%	325.5	Chevrolet C3500	397	Diesel	1	1	1	1	1	5	0.01	0.02	0.02	0.06	0.14	48	0.01
MECH TRUCK	2%	21.7	GMC 1500	250	Gas	1	1	1	1	1	5	0.00	0.00	0.00	0.00	0.00	2	0.00
B - EARTH MOVING																		
450 CASE DOZER	100%	6510	Case 650L	74	Diesel	6	6	6	6	6	30	0.06	0.07	0.07	0.51	0.82	146	0.03
580 BACKHOE	100%	2170	Case 580N	78	Diesel	2	2	2	2	2	10	0.04	0.04	0.04	0.25	0.20	30	0.01
225 TRACK HOE	100%	3255	Case CX210C	160	Diesel	3	3	3	3	3	15	0.06	0.05	0.05	0.24	0.40	57	0.01
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	217	Case 885B	214	Diesel	2	2	2	2	2	10	0.01	0.01	0.01	0.02	0.06	17	0.00
SHEEPSFOOT	50%	2170	Caterpillar CP54B	131	Diesel	4	4	4	4	4	20	0.04	0.05	0.05	0.18	0.44	100	0.02
DRUM ROLLER	50%	2170	Caterpiller CS44	100	Diesel	4	4	4	4	4	20	0.03	0.05	0.05	0.31	0.34	71	0.01
											Total	***0.64***	***0.73***	***0.71***	***3.11***	***6.43***	***1817***	***0.33***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

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Table 9.A.3 - Phase II LNG Tank Construction Emissions - Year 2015

Magnolia LNG Project

Construction Equipment Utilization Matrix

LNG Tank Fabrication: Civil/Mechanical/Electrical/Instruments

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year					Equipment Months	NONROAD Emission Factor (gram/hr)						
						8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																		
PICK-UP TRUCK older then 2010	10%	325.5	GMC 1500	250	Gas	3	3	3	3	3	15.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
A - ROLLING EQUIP																		
2-T FLATBED TRUCK	50%	1085	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	10.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
DUMP TRUCK 6CY	100%	434	Mack Truck Granite Series	415	Diesel					2	2.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
CEMENT TRUCK	1%	4366.04	Mack Truck Granite Series	415	Diesel				1762	250	2012.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
CEMENT PUMP TRUCK	100%	4340	Putzmeister 70Z-Meter	450	Diesel				10	10	20.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
FARM TRACTOR w/TRAILER	100%	0	Kubota L4240	44	Diesel	Not Used					0.0	4.43	4.49	4.35	22.50	43.22	6,744	1.33
FUEL TRUCK	30%	325.5	Chevrolet C3500	397	Diesel	1	1	1	1	1	5.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
MECH TRUCK	2%	21.7	GMC 1500	250	Gas	1	1	1	1	1	5.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
BUS	1%	10.85	Blue Bird Vision	260	Diesel	1	1	1	1	1	5.0	31.47	30.51	29.60	118.91	362.12	73,925	14.12
FORKLIFT	100%	1085	Cat PD10000	77	Diesel	1	1	1	1	1	5.0	8.09	13.66	13.25	68.35	76.56	30,042	5.10
EXTEND-A-FORKLIFT	100%	4340	JLG 8042 Sky Trak Telehandler	100	Diesel	4	4	4	4	4	20.0	8.09	13.66	13.25	68.35	76.56	30,042	5.10
40' MANLIFT	100%	868	JLG 400S Telescopic Boom Lift	49	Diesel					4	4.0	16.51	9.06	8.79	60.30	53.40	6,594	1.36
60' MANLIFT	100%	0	JLG 600S Telescopic Boom Lift	49	Diesel	Not Used					0.0	16.51	9.06	8.79	60.30	53.40	6,594	1.36
100' MANLIFT	100%	0	JLG 1250AJP Articulating Boom Lift	87	Diesel	Not Used					0.0	20.70	15.91	15.43	104.59	94.77	12,194	2.47
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel					2	2.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
TRACTOR/40' FLOAT	20%	434	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	2	10.0	25.74	18.79	18.23	88.89	172.15	26,237	5.18
UTILITY CARTS (SITE TRANSP)	10%	325.5	John Deere HPX 4 x 4	21	Gas	3	3	3	3	3	15.0	41.74	0.99	0.91	2,558.85	16.59	9,039	1.86
B - EARTH MOVING																		
FARM TRACTOR	100%	434	Kubota L4240	44	Diesel				2		2.0	4.43	4.49	4.35	22.50	43.22	6,744	1.33
450 CASE DOZER	20%	86.8	Case 650L	74	Diesel				2		2.0	7.78	9.52	9.24	71.49	114.79	20,370	3.95
580 BACKHOE	75%	488.25	Case 580N	78	Diesel				3		3.0	17.81	16.23	15.74	104.35	85.04	12,687	2.55
225 TRACK HOE	75%	488.25	Case CX210C	160	Diesel				3		3.0	17.72	13.94	13.52	65.90	110.85	15,827	3.18
BOBCAT	30%	130.2	Bobcat S130 Skid Steer Loader	49	Diesel				2		2.0	7.32	5.94	5.76	32.88	45.45	6,546	1.32
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used					0.0							
PLATE COMPACTORS	25%	542.5	Central Machinery 91762	6.5	Gas				10		10.0	21.93	0.52	0.48	1,340.68	8.78	4,733	0.98
SHEEPSFOOT	25%	108.5	Caterpillar CP54B	131	Diesel				2		2.0	17.23	21.63	20.98	74.95	185.35	41,820	8.01
DRUM ROLLER	25%	108.5	Caterpiller CS44	100	Diesel				2		2.0	13.31	20.02	19.42	129.62	141.05	29,773	5.70
C - AIR OP EQUIP																		
185 COMPRESSOR	100%	2170	Sullair 185	61	Diesel	2	2	2	2	2	10.0	8.31	8.49	8.24	53.16	104.09	15,399	3.08
375 COMPRESSOR	100%	2170	Sullair 375HH	139	Diesel	2	2	2	2	2	10.0	13.67	12.35	11.98	40.20	160.20	29,461	5.76
BUSHING GUN	10%	173.6	N/A	N/A	Air					8	8.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D - HEAVY EQUIP																		
300-T CRAWLER	50%	0	Manitowac 2250	500	Diesel	Not Used					0.0	35.92	31.41	30.46	145.73	569.13	93,971	18.32
220-T CRAWLER	50%	0	Manitowac 14000	340	Diesel	Not Used					0.0	35.92	31.41	30.46	145.73	569.13	93,971	18.32
TOWER CRANE	100%	0	Terex SK 575-32	139	Diesel	Not Used					0.0	13.75	13.28	12.88	40.42	155.14	33,115	6.37
80-TON PICKER	25%	434	Manitowac 2250	500	Diesel	2	2	2	2		8.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
65-TON PICKER	25%	0	Grove RT770E	240	Diesel	Not Used					0.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
25-TON PICKER	100%	868	Grove YB7725	130	Diesel					4	4.0	14.99	19.99	19.39	49.19	124.67	50,790	8.67
8-TON CARRY DECK	100%	434	Grove YB4400	100	Diesel					2	2.0	10.16	11.98	11.62	65.67	111.85	22,344	4.30
3 -T FORK LIFT	100%	0	Cat PD10000	77	Diesel	Not Used					0.0	8.09	13.66	13.25	68.35	76.56	30,042	5.10
PILE DRIVER	100%	3472	Delmag D46-32/33	350	Diesel	4	4	4	4		16.0	62.61	67.58	65.55	407.31	935.17	139,995	27.65
F - PUMP EQUIP																		
2" CENT. PUMPS	5%	217	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	4	4	20.0	26.78	0.68	0.62	1,692.99	10.06	6,018	1.24
TEST PUMPS	100%	0	Air Operated	N/A	Air						0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																		
8-PAC WELDER'S	100%	0	Electric Driven	N/A	Electric						0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RIG WELDING TRUCK	100%	0	Lincoln Classic 300D	32.7	Diesel	Not Used					0.0	7.86	5.34	5.18	31.99	35.48	4,797	0.98
I - ELECTRICAL EQUIP																		
GENERATOR'S 5KW	100%	2170	Honda EM5000S	11.7	Gas					10	10.0	48.75	1.10	1.01	2,906.80	20.29	10,202	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2015 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year					Equipment Months	Annual Emission (ton)						
						8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
SK TRUCKS & CARS																		
PICK-UP TRUCK older then 2010	10%	325.5	GMC 1500	250	Gas	3	3	3	3	3	15.0	0.01	0.01	0.01	0.01	0.06	28	0.00
A - ROLLING EQUIP																		
2-T FLATBED TRUCK	50%	1085	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	10.0	0.03	0.03	0.03	0.05	0.20	92	0.01
DUMP TRUCK 6CY	100%	434	Mack Truck Granite Series	415	Diesel					2	2.0	0.02	0.02	0.02	0.08	0.19	64	0.01
CEMENT TRUCK	1%	4366	Mack Truck Granite Series	415	Diesel				1762	250	2012.0	0.19	0.22	0.21	0.76	1.94	640	0.11
CEMENT PUMP TRUCK	100%	4340	Putzmeister 70Z-Meter	450	Diesel				10	10	20.0	0.18	0.22	0.21	0.75	1.93	636	0.11
FARM TRACTOR w/TRAILER	100%	0	Kubota L4240	44	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
FUEL TRUCK	30%	325.5	Chevrolet C3500	397	Diesel	1	1	1	1	1	5.0	0.01	0.02	0.02	0.06	0.14	48	0.01
MECH TRUCK	2%	21.7	GMC 1500	250	Gas	1	1	1	1	1	5.0	0.00	0.00	0.00	0.00	0.00	2	0.00
BUS	1%	10.85	Blue Bird Vision	260	Diesel	1	1	1	1	1	5.0	0.00	0.00	0.00	0.00	0.00	1	0.00
FORKLIFT	100%	1085	Cat PD10000	77	Diesel	1	1	1	1	1	5.0	0.01	0.02	0.02	0.08	0.09	36	0.01
EXTEND-A-FORKLIFT	100%	4340	JLG 8042 Sky Trak Telehandler	100	Diesel	4	4	4	4	4	20.0	0.04	0.07	0.06	0.33	0.37	144	0.02
40' MANLIFT	100%	868	JLG 400S Telescopic Boom Lift	49	Diesel					4	4.0	0.02	0.01	0.01	0.06	0.05	6	0.00
60' MANLIFT	100%	0	JLG 600S Telescopic Boom Lift	49	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
100' MANLIFT	100%	0	JLG 1250AJP Articulating Boom Lift	87	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel					2	2.0	0.02	0.02	0.02	0.08	0.19	64	0.01
TRACTOR/40' FLOAT	20%	434	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	2	10.0	0.01	0.01	0.01	0.04	0.08	13	0.00
UTILITY CARTS (SITE TRANSP)	10%	325.5	John Deere HPX 4 x 4	21	Gas	3	3	3	3	3	15.0	0.01	0.00	0.00	0.92	0.01	3	0.00
B - EARTH MOVING																		
FARM TRACTOR	100%	434	Kubota L4240	44	Diesel	Not Used			2		2.0	0.00	0.00	0.00	0.01	0.02	3	0.00
450 CASE DOZER	20%	86.8	Case 650L	74	Diesel				2		2.0	0.00	0.00	0.00	0.01	0.01	2	0.00
580 BACKHOE	75%	488.25	Case 580N	78	Diesel				3		3.0	0.01	0.01	0.01	0.06	0.05	7	0.00
225 TRACK HOE	75%	488.25	Case CX210C	160	Diesel				3		3.0	0.01	0.01	0.01	0.04	0.06	9	0.00
BOBCAT	30%	130.2	Bobcat S130 Skid Steer Loader	49	Diesel				2		2.0	0.00	0.00	0.00	0.00	0.01	1	0.00
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PLATE COMPACTORS	25%	542.5	Central Machinery 91762	6.5	Gas				10		10.0	0.01	0.00	0.00	0.80	0.01	3	0.00
SHEEPSFOOT	25%	108.5	Caterpillar CP54B	131	Diesel				2		2.0	0.00	0.00	0.00	0.01	0.02	5	0.00
DRUM ROLLER	25%	108.5	Caterpiller CS44	100	Diesel				2		2.0	0.00	0.00	0.00	0.02	0.02	4	0.00
C - AIR OP EQUIP																		
185 COMPRESSOR	100%	2170	Sullair 185	61	Diesel	2	2	2	2	2	10.0	0.02	0.02	0.02	0.13	0.25	37	0.01
375 COMPRESSOR	100%	2170	Sullair 375HH	139	Diesel	2	2	2	2	2	10.0	0.03	0.03	0.03	0.10	0.38	70	0.01
BUSHING GUN	10%	173.6	N/A	N/A	Air					8	8.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D - HEAVY EQUIP																		
300-T CRAWLER	50%	0	Manitowac 2250	500	Diesel						0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
220-T CRAWLER	50%	0	Manitowac 14000	340	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
TOWER CRANE	100%	0	Terex SK 575-32	139	Diesel						0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
80-TON PICKER	25%	434	Manitowac 2250	500	Diesel	2	2	2	2		8.0	0.02	0.02	0.02	0.08	0.19	64	0.01
65-TON PICKER	25%	0	Grove RT770E	240	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
25-TON PICKER	100%	868	Grove YB7725	130	Diesel					4	4.0	0.01	0.02	0.02	0.05	0.12	49	0.01
8-TON CARRY DECK	100%	434	Grove YB4400	100	Diesel					2	2.0	0.00	0.01	0.01	0.03	0.05	11	0.00
3 -T FORK LIFT	100%	0	Cat PD10000	77	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PILE DRIVER	100%	3472	Delmag D46-32/33	350	Diesel	4	4	4	4		16.0	0.24	0.26	0.25	1.56	3.58	536	0.11
F - PUMP EQUIP																		
2" CENT. PUMPS	5%	217	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	4	4	20.0	0.01	0.00	0.00	0.40	0.00	1	0.00
TEST PUMPS	100%	0	Air Operated	N/A	Air						0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																		
8-PAC WELDER'S	100%	0	Electric Driven	N/A	Electric						0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RIG WELDING TRUCK	100%	0	Lincoln Classic 300D	32.7	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
I - ELECTRICAL EQUIP																		
GENERATOR'S 5KW	100%	2170	Honda EM5000S	11.7	Gas					10	10.0	0.12	0.00	0.00	6.95	0.05	24	0.01
Total												*1.04*	*1.01*	*0.98*	*13.45*	*10.07*	*2599*	*0.47*

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.4 - Phase II LNG Tank Construction Emissions - Year 2016

Magnolia LNG Project

Construction Equipment Utilization Matrix

LNG Tank Fabrication: Civil/Mechanical/Electrical/Instruments

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK older then 2010	10%	781.2	GMC 1500	250	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	2604	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
DUMP TRUCK 6CY	100%	1302	Mack Truck Granite Series	415	Diesel	2	2	2										6.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
CEMENT TRUCK	1%	5967.5	Mack Truck Granite Series	415	Diesel	250	250	250	250	250	250	250	250	250	250	250		2750.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
CEMENT PUMP TRUCK	100%	23870	Putzmeister 70Z-Meter	450	Diesel	10	10	10	10	10	10	10	10	10	10	10		110.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
FARM TRACTOR w/TRAILER	100%	7812	Kubota L4240	44	Diesel				4	4	4	4	4	4	4	4	4	36.0	3.74	3.91	3.79	18.92	41.17	6,746	1.29
FUEL TRUCK	30%	781.2	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
MECH TRUCK	2%	52.08	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	1	1	1	1	12.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
BUS	1%	26.04	Blue Bird Vision	260	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	29.44	28.94	28.07	106.06	318.14	73,931	13.81
FORKLIFT	100%	2604	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	7.48	10.14	9.83	41.50	52.52	30,043	4.84
EXTEND-A-FORKLIFT	100%	10416	JLG 8042 Sky Trak Telehandler	100	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	7.48	10.14	9.83	41.50	52.52	30,043	4.84
40' MANLIFT	100%	6076	JLG 400S Telescopic Boom Lift	49	Diesel	4	4	4								8	8	28.0	15.24	8.56	8.30	56.07	51.77	6,598	1.34
60' MANLIFT	100%	3472	JLG 600S Telescopic Boom Lift	49	Diesel				4	4	4	4						16.0	15.24	8.56	8.30	56.07	51.77	6,598	1.34
100' MANLIFT	100%	3255	JLG 1250AJP Articulating Boom Lift	87	Diesel								5	5	5			15.0	19.32	15.05	14.60	98.87	88.84	12,198	2.44
1-T STAKEBED TRUCK	100%	5208	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
TRACTOR/40' FLOAT	20%	1041.6	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	23.79	17.71	17.18	81.06	158.04	26,243	5.10
UTILITY CARTS (SITE TRANSP)	10%	781.2	John Deere HPX 4 x 4	21	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	5.91	4.53	4.39	30.24	55.48	7,404	1.59
B - EARTH MOVING																									
FARM TRACTOR	100%	0	Kubota L4240	44	Diesel	Not Used												0.0	3.74	3.91	3.79	18.92	41.17	6,746	1.29
450 CASE DOZER	20%	0	Case 650L	74	Diesel	Not Used												0.0	6.92	8.63	8.38	60.52	110.47	20,373	3.81
580 BACKHOE	75%	0	Case 580N	78	Diesel	Not Used												0.0	16.17	15.11	14.66	96.80	78.44	12,692	2.51
225 TRACK HOE	75%	0	Case CX210C	160	Diesel	Not Used												0.0	16.19	13.12	12.72	59.05	101.17	15,832	3.13
BOBCAT	30%	0	Bobcat S130 Skid Steer Loader	49	Diesel	Not Used												0.0	6.41	5.41	5.25	29.06	43.63	6,549	1.29
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used												0.0							
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas	Not Used												0.0	21.12	0.52	0.48	1,331.65	8.19	4,734	0.98
SHEEPSFOOT	25%	0	Caterpillar CP54B	131	Diesel	Not Used												0.0	15.83	20.46	19.85	65.93	159.22	41,824	7.79
DRUM ROLLER	25%	0	Caterpiller CS44	100	Diesel	Not Used												0.0	11.96	18.50	17.95	114.58	121.88	29,777	5.54
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	13020	Sullair 185	61	Diesel	2	2	2	6	6	6	6	6	6	6	6	6	60.0	7.57	7.88	7.64	48.59	99.84	15,402	3.01
375 COMPRESSOR	100%	6076	Sullair 375HH	139	Diesel	2	2	2	2	2	2	2	2	2	2	2	6	28.0	12.77	11.82	11.46	36.21	140.82	29,464	5.63
BUSHING GUN	10%	520.8	N/A	N/A	Air	8	8	8										24.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D - HEAVY EQUIP																									
300-T CRAWLER	50%	2387	Manitowac 2250	500	Diesel		2	2	2	2	2	2	2	2	2	2	2	22.0	34.32	30.32	29.41	131.56	511.67	93,976	17.98
220-T CRAWLER	50%	1193.5	Manitowac 14000	340	Diesel		1	1	1	1	1	1	1	1	1	1	1	11.0	34.32	30.32	29.41	131.56	511.67	93,976	17.98
TOWER CRANE	100%	9548	Terex SK 575-32	139	Diesel		4	4	4	4	4	4	4	4	4	4	4	44.0	12.69	12.70	12.32	35.77	133.50	33,118	6.20
80-TON PICKER	25%	0	Manitowac 2250	500	Diesel	Not Used												0.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
65-TON PICKER	25%	976.5	Grove RT770E	240	Diesel				2	2	2	2	2	2	2	2	2	18.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
25-TON PICKER	100%	10416	Grove YB7725	130	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	14.01	16.01	15.53	30.48	88.38	50,793	8.22
8-TON CARRY DECK	100%	5208	Grove YB4400	100	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	9.17	11.16	10.82	58.43	96.96	22,347	4.18
3 -T FORK LIFT	100%	3906	Cat PD10000	77	Diesel				2	2	2	2	2	2	2	2	2	18.0	7.48	10.14	9.83	41.50	52.52	30,043	4.84
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel	Not Used												0.0	59.17	64.25	62.32	370.44	857.50	140,006	27.21
F - PUMP EQUIP																									
2" CENT. PUMPS	5%	325.5	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	2	2	2	2	2	2	2	2	2	30.0	26.29	0.68	0.62	1,687.58	9.70	6,018	1.24
TEST PUMPS	100%	0	Air Operated	N/A	Air													0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																									
8-PAC WELDER'S	100%	9114	Electric Driven	N/A	Electric		2	2	2	2	4	4	4	4	4	4	10	42.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RIG WELDING TRUCK	100%	1736	Lincoln Classic 300D	32.7	Diesel												8	8.0	6.82	4.87	4.72	28.30	34.05	4,800	0.96
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	26040	Honda EM5000S	11.7	Gas	10	10	10	10	10	10	10	10	10	10	10	10	120.0	45.91	1.10	1.01	2,875.10	18.19	10,205	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2016 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK older then 2010	10%	781.2	GMC 1500	250	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	0.02	0.02	0.02	0.03	0.11	67	0.01
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	2604	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.06	0.06	0.06	0.08	0.36	222	0.04
DUMP TRUCK 6CY	100%	1302	Mack Truck Granite Series	415	Diesel	2	2	2										6.0	0.05	0.06	0.06	0.18	0.47	191	0.03
CEMENT TRUCK	1%	5967.5	Mack Truck Granite Series	415	Diesel	250	250	250	250	250	250	250	250	250	250	250		2750.0	0.25	0.28	0.27	0.81	2.17	874	0.15
CEMENT PUMP TRUCK	100%	23870	Putzmeister 70Z-Meter	450	Diesel	10	10	10	10	10	10	10	10	10	10	10		110.0	0.98	1.10	1.07	3.26	8.67	3496	0.60
FARM TRACTOR w/TRAILER	100%	7812	Kubota L4240	44	Diesel				4	4	4	4	4	4	4	4	4	36.0	0.03	0.03	0.03	0.16	0.35	58	0.01
FUEL TRUCK	30%	781.2	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.03	0.04	0.03	0.11	0.28	114	0.02
MECH TRUCK	2%	52.08	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.00	0.01	4	0.00
BUS	1%	26.04	Blue Bird Vision	260	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.00	0.01	2	0.00
FORKLIFT	100%	2604	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.02	0.03	0.03	0.12	0.15	86	0.01
EXTEND-A-FORKLIFT	100%	10416	JLG 8042 Sky Trak Telehandler	100	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	0.09	0.12	0.11	0.48	0.60	345	0.06
40' MANLIFT	100%	6076	JLG 400S Telescopic Boom Lift	49	Diesel	4	4	4								8	8	28.0	0.10	0.06	0.06	0.38	0.35	44	0.01
60' MANLIFT	100%	3472	JLG 600S Telescopic Boom Lift	49	Diesel				4	4	4	4						16.0	0.06	0.03	0.03	0.21	0.20	25	0.01
100' MANLIFT	100%	3255	JLG 1250AJP Articulating Boom Lift	87	Diesel								5	5	5			15.0	0.07	0.05	0.05	0.35	0.32	44	0.01
1-T STAKEBED TRUCK	100%	5208	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.21	0.24	0.23	0.71	1.89	763	0.13
TRACTOR/40' FLOAT	20%	1041.6	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.03	0.02	0.02	0.09	0.18	30	0.01
UTILITY CARTS (SITE TRANSP)	10%	781.2	John Deere HPX 4 x 4	21	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	0.01	0.00	0.00	0.03	0.05	6	0.00
B - EARTH MOVING																									
FARM TRACTOR	100%	0	Kubota L4240	44	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
450 CASE DOZER	20%	0	Case 650L	74	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
580 BACKHOE	75%	0	Case 580N	78	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
225 TRACK HOE	75%	0	Case CX210C	160	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
BOBCAT	30%	0	Bobcat S130 Skid Steer Loader	49	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
SHEEPSFOOT	25%	0	Caterpillar CP54B	131	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
DRUM ROLLER	25%	0	Caterpiller CS44	100	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	13020	Sullair 185	61	Diesel	2	2	2	6	6	6	6	6	6	6	6	6	60.0	0.11	0.11	0.11	0.70	1.43	221	0.04
375 COMPRESSOR	100%	6076	Sullair 375HH	139	Diesel	2	2	2	2	2	2	2	2	2	2	2	6	28.0	0.09	0.08	0.08	0.24	0.94	197	0.04
BUSHING GUN	10%	520.8	N/A	N/A	Air	8	8	8										24.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D - HEAVY EQUIP																									
300-T CRAWLER	50%	2387	Manitowac 2250	500	Diesel		2	2	2	2	2	2	2	2	2	2	2	22.0	0.09	0.08	0.08	0.35	1.35	247	0.05
220-T CRAWLER	50%	1193.5	Manitowac 14000	340	Diesel		1	1	1	1	1	1	1	1	1	1	1	11.0	0.05	0.04	0.04	0.17	0.67	124	0.02
TOWER CRANE	100%	9548	Terex SK 575-32	139	Diesel		4	4	4	4	4	4	4	4	4	4	4	44.0	0.13	0.13	0.13	0.38	1.41	349	0.07
80-TON PICKER	25%	0	Manitowac 2250	500	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
65-TON PICKER	25%	976.5	Grove RT770E	240	Diesel				2	2	2	2	2	2	2	2	2	18.0	0.02	0.02	0.02	0.03	0.13	83	0.01
25-TON PICKER	100%	10416	Grove YB7725	130	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	0.16	0.18	0.18	0.35	1.01	583	0.09
8-TON CARRY DECK	100%	5208	Grove YB4400	100	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.05	0.06	0.06	0.34	0.56	128	0.02
3 -T FORK LIFT	100%	3906	Cat PD10000	77	Diesel				2	2	2	2	2	2	2	2	2	18.0	0.03	0.04	0.04	0.18	0.23	129	0.02
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
F - PUMP EQUIP																									
2" CENT. PUMPS	5%	325.5	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	2	2	2	2	2	2	2	2	2	30.0	0.01	0.00	0.00	0.61	0.00	2	0.00
TEST PUMPS	100%	0	Air Operated	N/A	Air													0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																									
8-PAC WELDER'S	100%	9114	Electric Driven	N/A	Electric		2	2	2	2	4	4	4	4	4	4	10	42.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RIG WELDING TRUCK	100%	1736	Lincoln Classic 300D	32.7	Diesel												8	8.0	0.01	0.01	0.01	0.05	0.07	9	0.00
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	26040	Honda EM5000S	11.7	Gas	10	10	10	10	10	10	10	10	10	10	10	10	120.0	1.32	0.03	0.03	82.53	0.52	293	0.06
Total																			*4.08*	*2.94*	*2.85*	*92.92*	*24.49*	*8739*	*1.52*

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.5 - Phase II LNG Tank Construction Emissions - Year 2017

Magnolia LNG Project

Construction Equipment Utilization Matrix

LNG Tank Fabrication: Civil/Mechanical/Electrical/Instruments

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK older then 2010	10%	781.2	GMC 1500	250	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	13.62	14.33	13.90	22.60	63.89	50,794	8.04
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	2604	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	13.62	14.33	13.90	22.60	63.89	50,794	8.04
DUMP TRUCK 6CY	100%	0	Mack Truck Granite Series	415	Diesel	Not Used												0.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
CEMENT TRUCK	1%	0	Mack Truck Granite Series	415	Diesel	Not Used												0.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
CEMENT PUMP TRUCK	100%	0	Putzmeister 70Z-Meter	450	Diesel	Not Used												0.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
FARM TRACTOR w/TRAILER	100%	10416	Kubota L4240	44	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	3.15	3.37	3.27	15.69	39.25	6,747	1.26
FUEL TRUCK	30%	781.2	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
MECH TRUCK	2%	52.08	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	1	1	1	1	12.0	20.42	19.62	19.03	23.53	91.28	77,315	12.08
BUS	1%	26.04	Blue Bird Vision	260	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	27.56	27.66	26.83	93.98	279.40	73,936	13.50
FORKLIFT	100%	2604	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	7.25	8.81	8.54	31.48	36.80	30,044	4.74
EXTEND-A-FORKLIFT	100%	10416	JLG 8042 Sky Trak Telehandler	100	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	7.25	8.81	8.54	31.48	36.80	30,044	4.74
40' MANLIFT	100%	3472	JLG 400S Telescopic Boom Lift	49	Diesel	8	8											16.0	14.00	8.07	7.82	51.94	50.18	6,602	1.32
60' MANLIFT	100%	6944	JLG 600S Telescopic Boom Lift	49	Diesel			8	8	8	8							32.0	14.00	8.07	7.82	51.94	50.18	6,602	1.32
100' MANLIFT	100%	10416	JLG 1250AJP Articulating Boom Lift	87	Diesel							8	8	8	8	8	8	48.0	17.99	14.21	13.79	93.32	83.15	12,202	2.41
1-T STAKEBED TRUCK	100%	5208	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
TRACTOR/40' FLOAT	20%	1041.6	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	22.02	16.71	16.21	74.14	144.77	26,248	5.02
UTILITY CARTS (SITE TRANSP)	10%	781.2	John Deere HPX 4 x 4	21	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	5.89	4.52	4.38	29.88	55.49	7,404	1.59
B - EARTH MOVING																									
FARM TRACTOR	100%	0	Kubota L4240	44	Diesel	Not Used												0.0	3.15	3.37	3.27	15.69	39.25	6,747	1.26
450 CASE DOZER	20%	0	Case 650L	74	Diesel	Not Used												0.0	6.37	7.94	7.70	51.43	108.16	20,374	3.69
580 BACKHOE	75%	0	Case 580N	78	Diesel	Not Used												0.0	14.62	14.03	13.61	89.60	72.13	12,696	2.47
225 TRACK HOE	75%	0	Case CX210C	160	Diesel	Not Used												0.0	14.96	12.42	12.04	54.10	92.73	15,836	3.08
BOBCAT	30%	0	Bobcat S130 Skid Steer Loader	49	Diesel	Not Used												0.0	5.58	4.92	4.77	25.52	41.91	6,552	1.26
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used												0.0							
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas	Not Used												0.0	20.49	0.52	0.48	1,325.03	7.76	4,734	0.98
SHEEPSFOOT	25%	0	Caterpillar CP54B	131	Diesel	Not Used												0.0	14.60	19.27	18.69	57.53	135.36	41,827	7.58
DRUM ROLLER	25%	0	Caterpiller CS44	100	Diesel	Not Used												0.0	10.76	17.08	16.57	100.19	104.00	29,780	5.39
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	15624	Sullair 185	61	Diesel	6	6	6	6	6	6	6	6	6	6	6	6	72.0	6.89	7.30	7.08	44.22	95.93	15,404	2.94
375 COMPRESSOR	100%	15624	Sullair 375HH	139	Diesel	6	6	6	6	6	6	6	6	6	6	6	6	72.0	11.93	11.35	11.01	32.47	123.85	29,466	5.50
BUSHING GUN	10%	0	N/A	N/A	Air													0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D - HEAVY EQUIP																									
300-T CRAWLER	50%	0	Manitowac 2250	500	Diesel	Not Used												0.0	32.90	29.35	28.47	118.31	457.62	93,980	17.66
220-T CRAWLER	50%	1302	Manitowac 14000	340	Diesel	2	2	2	2	2	2							12.0	32.90	29.35	28.47	118.31	457.62	93,980	17.66
TOWER CRANE	100%	0	Terex SK 575-32	139	Diesel	Not Used												0.0	11.72	12.13	11.77	31.38	113.55	33,121	6.04
80-TON PICKER	25%	0	Manitowac 2250	500	Diesel	Not Used												0.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
65-TON PICKER	25%	54.25	Grove RT770E	240	Diesel	1												1.0	20.42	19.62	19.03	23.53	91.28	77,315	12.08
25-TON PICKER	100%	10416	Grove YB7725	130	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	13.62	14.33	13.90	22.60	63.89	50,794	8.04
8-TON CARRY DECK	100%	5208	Grove YB4400	100	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	8.29	10.39	10.08	51.49	83.03	22,350	4.08
3 -T FORK LIFT	100%	5208	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	7.25	8.81	8.54	31.48	36.80	30,044	4.74
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel	Not Used												0.0	56.26	61.29	59.45	336.86	784.31	140,014	26.78
F - PUMP EQUIP																									
2" CENT. PUMPS	5%	260.4	DuroMax Portable 2" Water Pump	7	Gas	2	2	2	2	2	2	2	2	2	2	2	2	24.0	25.96	0.68	0.63	1,684.17	9.48	6,019	1.24
TEST PUMPS	100%	4340	Air Operated	N/A	Air								4	4	4	4	4	20.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																									
8-PAC WELDER'S	100%	22134	Electric Driven	N/A	Electric	10	10	10	10	10	10	10	10	10	6	4	2	102.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RIG WELDING TRUCK	100%	18228	Lincoln Classic 300D	32.7	Diesel	8	8	8	8	8	8	8	8	8	6	4	2	84.0	5.86	4.42	4.29	24.86	32.70	4,803	0.94
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	26040	Honda EM5000S	11.7	Gas	10	10	10	10	10	10	10	10	10	10	10	10	120.0	44.53	1.10	1.01	2,859.98	17.19	10,206	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2017 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK older then 2010	10%	781.2	GMC 1500	250	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	0.01	0.01	0.01	0.02	0.06	44	0.01
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	2604	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.04	0.04	0.04	0.06	0.18	146	0.02
DUMP TRUCK 6CY	100%	0	Mack Truck Granite Series	415	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
CEMENT TRUCK	1%	0	Mack Truck Granite Series	415	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
CEMENT PUMP TRUCK	100%	0	Putzmeister 70Z-Meter	450	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
FARM TRACTOR w/TRAILER	100%	10416	Kubota L4240	44	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	0.04	0.04	0.04	0.18	0.45	77	0.01
FUEL TRUCK	30%	781.2	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.03	0.03	0.03	0.08	0.23	114	0.02
MECH TRUCK	2%	52.08	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.00	0.01	4	0.00
BUS	1%	26.04	Blue Bird Vision	260	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.00	0.01	2	0.00
FORKLIFT	100%	2604	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.02	0.03	0.02	0.09	0.11	86	0.01
EXTEND-A-FORKLIFT	100%	10416	JLG 8042 Sky Trak Telehandler	100	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	0.08	0.10	0.10	0.36	0.42	345	0.05
40' MANLIFT	100%	3472	JLG 400S Telescopic Boom Lift	49	Diesel	8	8											16.0	0.05	0.03	0.03	0.20	0.19	25	0.01
60' MANLIFT	100%	6944	JLG 600S Telescopic Boom Lift	49	Diesel			8	8	8	8							32.0	0.11	0.06	0.06	0.40	0.38	51	0.01
100' MANLIFT	100%	10416	JLG 1250AJP Articulating Boom Lift	87	Diesel							8	8	8	8	8	8	48.0	0.21	0.16	0.16	1.07	0.95	140	0.03
1-T STAKEBED TRUCK	100%	5208	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.21	0.22	0.21	0.53	1.51	763	0.13
TRACTOR/40' FLOAT	20%	1041.6	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.03	0.02	0.02	0.09	0.17	30	0.01
UTILITY CARTS (SITE TRANSP)	10%	781.2	John Deere HPX 4 x 4	21	Gas	3	3	3	3	3	3	3	3	3	3	3	3	36.0	0.01	0.00	0.00	0.03	0.05	6	0.00
B - EARTH MOVING																									
FARM TRACTOR	100%	0	Kubota L4240	44	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
450 CASE DOZER	20%	0	Case 650L	74	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
580 BACKHOE	75%	0	Case 580N	78	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
225 TRACK HOE	75%	0	Case CX210C	160	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
BOBCAT	30%	0	Bobcat S130 Skid Steer Loader	49	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
SHEEPSFOOT	25%	0	Caterpillar CP54B	131	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
DRUM ROLLER	25%	0	Caterpiller CS44	100	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	15624	Sullair 185	61	Diesel	6	6	6	6	6	6	6	6	6	6	6	6	72.0	0.12	0.13	0.12	0.76	1.65	265	0.05
375 COMPRESSOR	100%	15624	Sullair 375HH	139	Diesel	6	6	6	6	6	6	6	6	6	6	6	6	72.0	0.21	0.20	0.19	0.56	2.13	507	0.09
BUSHING GUN	10%	0	N/A	N/A	Air													0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D - HEAVY EQUIP																									
300-T CRAWLER	50%	0	Manitowac 2250	500	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
220-T CRAWLER	50%	1302	Manitowac 14000	340	Diesel	2	2	2	2	2	2							12.0	0.05	0.04	0.04	0.17	0.66	135	0.03
TOWER CRANE	100%	0	Terex SK 575-32	139	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
80-TON PICKER	25%	0	Manitowac 2250	500	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
65-TON PICKER	25%	54.25	Grove RT770E	240	Diesel	1												1.0	0.00	0.00	0.00	0.00	0.01	5	0.00
25-TON PICKER	100%	10416	Grove YB7725	130	Diesel	4	4	4	4	4	4	4	4	4	4	4	4	48.0	0.16	0.16	0.16	0.26	0.73	583	0.09
8-TON CARRY DECK	100%	5208	Grove YB4400	100	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.05	0.06	0.06	0.30	0.48	128	0.02
3 -T FORK LIFT	100%	5208	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.04	0.05	0.05	0.18	0.21	172	0.03
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel	Not Used												0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
F - PUMP EQUIP																									
2" CENT. PUMPS	5%	260.4	DuroMax Portable 2" Water Pump	7	Gas	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.01	0.00	0.00	0.48	0.00	2	0.00
TEST PUMPS	100%	4340	Air Operated	N/A	Air								4	4	4	4	4	20.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																									
8-PAC WELDER'S	100%	22134	Electric Driven	N/A	Electric	10	10	10	10	10	10	10	10	10	6	4	2	102.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RIG WELDING TRUCK	100%	18228	Lincoln Classic 300D	32.7	Diesel	8	8	8	8	8	8	8	8	8	6	4	2	84.0	0.12	0.09	0.09	0.50	0.66	96	0.02
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	26040	Honda EM5000S	11.7	Gas	10	10	10	10	10	10	10	10	10	10	10	10	120.0	1.28	0.03	0.03	82.09	0.49	293	0.06

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Total	*2.85*	*1.51*	*1.47*	*88.41*	*11.73*	*4022*	*0.70*

Table 9.A.6 - Phase III LNG Tank Construction Emissions - Year 2015

Magnolia LNG Project
Construction Equipment Utilization Matrix
Balance of Plant: All Disciplines

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year				Equipment Months	NONROAD Emission Factor (gram/hr)						
						9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																	
PICK-UP TRUCK or VAN newer then 2010	10%	238.7	GMC 1500	250	Diesel	2	2	2	5	11.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
A - ROLLING EQUIP																	
2-T FLATBED TRUCK	50%	651	Chevrolet Kodiak C5500	300	Diesel	1	1	1	3	6.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
DUMP TRUCK 6CY	100%	434	Mack Truck Granite Series	415	Diesel				2	2.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
FARM TRACTOR w/TRAILER	100%	0	Kubota L4240	44	Diesel	Not Used				0.0	4.43	4.49	4.35	22.50	43.22	6,744	1.33
CEMENT TRUCK	15%	3255	Mack Truck Granite Series	415	Diesel				100	100.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
CEMENT PUMP TRUCK	100%	217	Putzmeister 70Z-Meter	450	Diesel				1	1.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
FUEL TRUCK	30%	260.4	Chevrolet C3500	397	Diesel	1	1	1	1	4.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
MECH TRUCK	2%	17.36	GMC 1500	250	Diesel	1	1	1	1	4.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
BUS	1%	0	Blue Bird Vision	260	Diesel	Not Used				0.0	31.47	30.51	29.60	118.91	362.12	73,925	14.12
SCISSOR LIFT	50%	0	Electric Operated	N/A	Electric					0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EXTEND-A-FORKLIFT	100%	1736	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	8.0	8.09	13.66	13.25	68.35	76.56	30,042	5.10
40' MANLIFT	100%	434	JLG 400S Telescopic Boom Lift	49	Diesel				2	2.0	16.51	9.06	8.79	60.30	53.40	6,594	1.36
60' MANLIFT	100%	0	JLG 600S Telescopic Boom Lift	49	Diesel	Not Used				0.0	16.51	9.06	8.79	60.30	53.40	6,594	1.36
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel				2	2.0	38.53	45.09	43.74	157.72	403.14	132,878	23.48
TRACTOR/40' FLOAT	20%	347.2	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	8.0	25.74	18.79	18.23	88.89	172.15	26,237	5.18
UTILITY CARTS (SITE TRANSP)	10%	43.4	John Deere HPX 4 x 4	21	Gas				2	2.0	41.74	0.99	0.91	2,558.85	16.59	9,039	1.86
B - EARTH MOVING																	
580 BACKHOE	100%	434	Case 580N	78	Diesel				2	2.0	17.81	16.23	15.74	104.35	85.04	12,687	2.55
225 TRACK HOE	100%	434	Case CX210C	160	Diesel				2	2.0	17.72	13.94	13.52	65.90	110.85	15,827	3.18
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	0	Case 885B	214	Diesel	Not Used				0.0	24.38	26.28	25.49	84.59	248.66	73,154	13.19
BOBCAT	30%	65.1	Bobcat S130 Skid Steer Loader	49	Diesel				1	1.0	7.32	5.94	5.76	32.88	45.45	6,546	1.32
DITCH WITCH	10%	0	Bobcat E32	33.3	Diesel	Not Used				0.0	3.11	3.15	3.06	15.81	30.37	4,739	0.93
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used				0.0	121.37	19.12	17.59	578.84	2.73	1,435	0.29
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas	Not Used				0.0	21.93	0.52	0.48	1,340.68	8.78	4,733	0.98
C - AIR OP EQUIP																	
185 COMPRESSOR	100%	434	Sullair 185	61	Diesel				2	2.0	8.31	8.49	8.24	53.16	104.09	15,399	3.08
375 COMPRESSOR	100%	1736	Sullair 375HH	139	Diesel	2	2	2	2	8.0	13.67	12.35	11.98	40.20	160.20	29,461	5.76
D - HEAVY EQUIP																	
MODULE SET/HEAVY LIFT CRANE	10%	0	Manitowac 31000	600	Diesel	Not Used				0.0	35.92	31.41	30.46	145.73	569.13	93,971	18.32
220-T CRAWLER	100%	0	Manitowac 14000	340	Diesel	Not Used				0.0	35.92	31.41	30.46	145.73	569.13	93,971	18.32
80-TON PICKER	100%	1736	Grove RT880E	275	Diesel	2	2	2	2	8.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
35-TON PICKER	100%	0	Grove RT530E-2	164	Diesel	Not Used				0.0	14.99	19.99	19.39	49.19	124.67	50,790	8.67
25-TON PICKER	100%	1953	Grove YB7725	130	Diesel	2	2	2	3	9.0	14.99	19.99	19.39	49.19	124.67	50,790	8.67
8-TON CARRY DECK	100%	0	Grove YB4400	100	Diesel	Not Used				0.0	10.16	11.98	11.62	65.67	111.85	22,344	4.30
PILE DRIVER	100%	1736	Delmag D46-32/33	350	Diesel	2	2	2	2	8.0	62.61	67.58	65.55	407.31	935.17	139,995	27.65
F - PUMP EQUIP																	
2" CENT. PUMPS	5%	43.4	DuroMax Portable 2" Water Pump	7	Gas				4	4.0	26.78	0.68	0.62	1,692.99	10.06	6,018	1.24
TEST PUMPS	100%	0	Air Operated	N/A	Air					0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																	
RIG WELD TRUCK	100%	0	Electric Driven	N/A	Electric					0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8-PAC WELDER'S	100%	0	Lincoln Classic 300D Engine Driven Weld Machine	32.7	Diesel	Not Used				0.0	7.86	5.34	5.18	31.99	35.48	4,797	0.98
I - ELECTRICAL EQUIP																	
GENERATOR'S 5KW	100%	868	Honda EM5000S	11.7	Gas	Not Used			4	4.0	48.75	1.10	1.01	2,906.80	20.29	10,202	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2015 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year				Equipment Months	Annual Emission (ton)						
						9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
SK TRUCKS & CARS																	
PICK-UP TRUCK or VAN newer then 2010	10%	238.7	GMC 1500	250	Diesel	2	2	2	5	11.0	0.01	0.01	0.01	0.01	0.04	20	0.00
A - ROLLING EQUIP																	
2-T FLATBED TRUCK	50%	651	Chevrolet Kodiak C5500	300	Diesel	1	1	1	3	6.0	0.02	0.02	0.02	0.03	0.12	55	0.01
DUMP TRUCK 6CY	100%	434	Mack Truck Granite Series	415	Diesel				2	2.0	0.02	0.02	0.02	0.08	0.19	64	0.01
FARM TRACTOR w/TRAILER	100%	0	Kubota L4240	44	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
CEMENT TRUCK	15%	3255	Mack Truck Granite Series	415	Diesel				100	100.0	0.14	0.16	0.16	0.57	1.45	477	0.08
CEMENT PUMP TRUCK	100%	217	Putzmeister 70Z-Meter	450	Diesel				1	1.0	0.01	0.01	0.01	0.04	0.10	32	0.01
FUEL TRUCK	30%	260.4	Chevrolet C3500	397	Diesel	1	1	1	1	4.0	0.01	0.01	0.01	0.05	0.12	38	0.01
MECH TRUCK	2%	17.36	GMC 1500	250	Diesel	1	1	1	1	4.0	0.00	0.00	0.00	0.00	0.00	1	0.00
BUS	1%	0	Blue Bird Vision	260	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
SCISSOR LIFT	50%	0	Electric Operated	N/A	electric					0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EXTEND-A-FORKLIFT	100%	1736	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	8.0	0.02	0.03	0.03	0.13	0.15	57	0.01
40' MANLIFT	100%	434	JLG 400S Telescopic Boom Lift	49	Diesel				2	2.0	0.01	0.00	0.00	0.03	0.03	3	0.00
60' MANLIFT	100%	0	JLG 600S Telescopic Boom Lift	49	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel				2	2.0	0.02	0.02	0.02	0.08	0.19	64	0.01
TRACTOR/40' FLOAT	20%	347.2	Mack Truck Pinnacle Series	505	Diesel	2	2	2	2	8.0	0.01	0.01	0.01	0.03	0.07	10	0.00
UTILITY CARTS (SITE TRANSP)	10%	43.4	John Deere HPX 4 x 4	21	Gas				2	2.0	0.00	0.00	0.00	0.12	0.00	0	0.00
B - EARTH MOVING																	
580 BACKHOE	100%	434	Case 580N	78	Diesel				2	2.0	0.01	0.01	0.01	0.05	0.04	6	0.00
225 TRACK HOE	100%	434	Case CX210C	160	Diesel				2	2.0	0.01	0.01	0.01	0.03	0.05	8	0.00
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	0	Case 885B	214	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
BOBCAT	30%	65.1	Bobcat S130 Skid Steer Loader	49	Diesel				1	1.0	0.00	0.00	0.00	0.00	0.00	0	0.00
DITCH WITCH	10%	0	Bobcat E32	33.3	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
C - AIR OP EQUIP																	
185 COMPRESSOR	100%	434	Sullair 185	61	Diesel				2	2.0	0.00	0.00	0.00	0.03	0.05	7	0.00
375 COMPRESSOR	100%	1736	Sullair 375HH	139	Diesel	2	2	2	2	8.0	0.03	0.02	0.02	0.08	0.31	56	0.01
D - HEAVY EQUIP																	
MODULE SET/HEAVY LIFT CRANE	10%	0	Manitowac 31000	600	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
220-T CRAWLER	100%	0	Manitowac 14000	340	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
80-TON PICKER	100%	1736	Grove RT880E	275	Diesel	2	2	2	2	8.0	0.04	0.04	0.04	0.08	0.31	148	0.02
35-TON PICKER	100%	0	Grove RT530E-2	164	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
25-TON PICKER	100%	1953	Grove YB7725	130	Diesel	2	2	2	3	9.0	0.03	0.04	0.04	0.11	0.27	109	0.02
8-TON CARRY DECK	100%	0	Grove YB4400	100	Diesel					0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PILE DRIVER	100%	1736	Delmag D46-32/33	350	Diesel	2	2	2	2	8.0	0.12	0.13	0.13	0.78	1.79	268	0.05
F - PUMP EQUIP																	
2" CENT. PUMPS	5%	43.4	DuroMax Portable 2" Water Pump	7	Gas				4	4.0	0.00	0.00	0.00	0.08	0.00	0	0.00
TEST PUMPS	100%	0	Air Operated	N/A	Air					0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																	
RIG WELD TRUCK	100%	0	Electric Driven	N/A	Electric					0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8-PAC WELDER'S	100%	0	Lincoln Classic 300D Engine Driven Weld Machine	32.7	Diesel	Not Used				0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
I - ELECTRICAL EQUIP																	
GENERATOR'S 5KW	100%	868	Honda EM5000S	11.7	Gas				4	4.0	0.05	0.00	0.00	2.78	0.02	10	0.00
										Total	***0.54***	***0.55***	***0.53***	***5.16***	***5.29***	***1435***	***0.26***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.7 - Phase III LNG Tank Construction Emissions - Year 2016

Magnolia LNG Project

Construction Equipment Utilization Matrix

Balance of Plant: All Disciplines

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	303.8	GMC 1500	250	Diesel	5	5	5	14	14	14	14	9	9	9	9	8	115.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	325.5	Chevrolet Kodiak C5500	300	Diesel	3	3	3	3	3	3	3	2	2	2	2	2	31.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
DUMP TRUCK 6CY	100%	434	Mack Truck Granite Series	415	Diesel	2	2	2	2	2	2	2						14.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
FARM TRACTOR w/TRAILER	100%	0	Kubota L4240	44	Diesel								2	2	2	2	2	10.0	3.74	3.91	3.79	18.92	41.17	6,746	1.29
CEMENT TRUCK	15%	3255	Mack Truck Granite Series	415	Diesel	100	100	100	100	100	100	100						700.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
CEMENT PUMP TRUCK	100%	217	Putzmeister 70Z-Meter	450	Diesel	1	1	1	1	1	1	1						7.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
FUEL TRUCK	30%	65.1	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
MECH TRUCK	2%	4.34	GMC 1500	250	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
BUS	1%	2.17	Blue Bird Vision	260	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	29.44	28.94	28.07	106.06	318.14	73,931	13.81
SCISSOR LIFT	50%	217	Electric Operated	N/A	Electric				2	2	2	2	2	2	2	2	2	18.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EXTEND-A-FORKLIFT	100%	1302	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	6	6	6	6	6	6	6	6	6	60.0	7.48	10.14	9.83	41.50	52.52	30,043	4.84
40' MANLIFT	100%	1736	JLG 400S Telescopic Boom Lift	49	Diesel	2	2	2	8	8	8	8	6	6	6	6	6	68.0	15.24	8.56	8.30	56.07	51.77	6,598	1.34
60' MANLIFT	100%	868	JLG 600S Telescopic Boom Lift	49	Diesel				4	4	4	4	4	4	4	4	4	36.0	15.24	8.56	8.30	56.07	51.77	6,598	1.34
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	37.38	41.84	40.59	123.72	329.59	132,882	22.63
TRACTOR/40' FLOAT	20%	43.4	Mack Truck Pinnacle Series	505	Diesel	2	2	2	1	1	1	1	1	1	1	1	1	15.0	23.79	17.71	17.18	81.06	158.04	26,243	5.10
UTILITY CARTS (SITE TRANSP)	10%	151.9	John Deere HPX 4 x 4	21	Gas	2	2	2	7	7	7	7	7	7	7	7	6	68.0	5.91	4.53	4.39	30.24	55.48	7,404	1.59
B - EARTH MOVING																									
580 BACKHOE	100%	434	Case 580N	78	Diesel	2	2	2	2	2	2	2	2	2				18.0	16.17	15.11	14.66	96.80	78.44	12,692	2.51
225 TRACK HOE	100%	434	Case CX210C	160	Diesel	2	2	2	2	2	2	2	2	2				18.0	16.19	13.12	12.72	59.05	101.17	15,832	3.13
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	0	Case 885B	214	Diesel								1	1				2.0	23.02	24.53	23.79	69.68	207.46	73,158	12.76
BOBCAT	30%	65.1	Bobcat S130 Skid Steer Loader	49	Diesel	1	1	1	1	1	1	1	1	1				9.0	6.41	5.41	5.25	29.06	43.63	6,549	1.29
DITCH WITCH	10%	21.7	Bobcat E32	33.3	Diesel			1	1	1	1	1	1					6.0	2.63	2.75	2.66	13.29	28.93	4,741	0.91
GAS TAMPER	25%	108.5	Jumping Jack Tamper 115-130LB	4	Gas		2	2	2	2	2	2	2	2				16.0	121.37	19.12	17.59	578.84	2.73	1,435	0.29
PLATE COMPACTORS	25%	217	Central Machinery 91762	6.5	Gas		4	4	4	4	4	4	4	4				32.0	21.12	0.52	0.48	1,331.65	8.19	4,734	0.98
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	1302	Sullair 185	61	Diesel	2	2	2	6	6	6	6	6	6	6	6	6	60.0	7.57	7.88	7.64	48.59	99.84	15,402	3.01
375 COMPRESSOR	100%	217	Sullair 375HH	139	Diesel	2	2	2	1	1	1	1	1	1	1	1	1	15.0	12.77	11.82	11.46	36.21	140.82	29,464	5.63
D - HEAVY EQUIP																									
MODULE SET/HEAVY LIFT CRANE	10%	43.4	Manitowac 31000	600	Diesel				2	2	2	2	2	2	2	2	2	18.0	34.32	30.32	29.41	131.56	511.67	93,976	17.98
220-T CRAWLER	100%	868	Manitowac 14000	340	Diesel				4	4	4	4	4	4	4	4	4	36.0	34.32	30.32	29.41	131.56	511.67	93,976	17.98
80-TON PICKER	100%	651	Grove RT880E	275	Diesel	2	2	2	3	3	3	3	3	3	3	3	3	33.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
35-TON PICKER	100%	0	Grove RT530E-2	164	Diesel							2	2	2	2	2	2	12.0	14.01	16.01	15.53	30.48	88.38	50,793	8.22
25-TON PICKER	100%	651	Grove YB7725	130	Diesel	3	3	3	3	3	3	8	8	8	5	5	5	57.0	14.01	16.01	15.53	30.48	88.38	50,793	8.22
8-TON CARRY DECK	100%	0	Grove YB4400	100	Diesel							2	2	2	2	2	2	12.0	9.17	11.16	10.82	58.43	96.96	22,347	4.18
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel	2	2	2										6.0	59.17	64.25	62.32	370.44	857.50	140,006	27.21
F - PUMP EQUIP																									
2" CENT. PUMPS	5%	43.4	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	4	4	4	4	4	4	4	4	4	48.0	26.29	0.68	0.62	1,687.58	9.70	6,018	1.24
TEST PUMPS	100%	0	Air Operated	N/A	Air							2	2	2				6.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																									
RIG WELD TRUCK	100%	868	Electric Driven	N/A	Electric		4	4	4	4	4	12	11	10	8	8	8	77.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8-PAC WELDER'S	100%	0	Lincoln Classic 300D Engine Driven Weld Machine	32.7	Diesel							4	4	4	4	4	4	24.0	6.82	4.87	4.72	28.30	34.05	4,800	0.96
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	1302	Honda EM5000S	11.7	Gas	4	4	4	6	6	6	10	10	10	6	6	6	78.0	45.91	1.10	1.01	2,875.10	18.19	10,205	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2016 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	303.8	GMC 1500	250	Diesel	5	5	5	14	14	14	14	9	9	9	9	8	115.0	0.01	0.01	0.01	0.01	0.04	26	0.00
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	325.5	Chevrolet Kodiak C5500	300	Diesel	3	3	3	3	3	3	3	2	2	2	2	2	31.0	0.01	0.01	0.01	0.01	0.04	28	0.00
DUMP TRUCK 6CY	100%	434	Mack Truck Granite Series	415	Diesel	2	2	2	2	2	2	2						14.0	0.02	0.02	0.02	0.06	0.16	64	0.01
FARM TRACTOR w/TRAILER	100%	0	Kubota L4240	44	Diesel								2	2	2	2	2	10.0	0.00	0.00	0.00	0.00	0.00	0	0.00
CEMENT TRUCK	15%	3255	Mack Truck Granite Series	415	Diesel	100	100	100	100	100	100	100						700.0	0.13	0.15	0.15	0.44	1.18	477	0.08
CEMENT PUMP TRUCK	100%	217	Putzmeister 70Z-Meter	450	Diesel	1	1	1	1	1	1	1						7.0	0.01	0.01	0.01	0.03	0.08	32	0.01
FUEL TRUCK	30%	65.1	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.01	0.02	10	0.00
MECH TRUCK	2%	4.34	GMC 1500	250	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.00	0.00	0	0.00
BUS	1%	2.17	Blue Bird Vision	260	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	0.00	0.00	0.00	0.00	0.00	0	0.00
SCISSOR LIFT	50%	217	Electric Operated	N/A	Electric				2	2	2	2	2	2	2	2	2	18.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EXTEND-A-FORKLIFT	100%	1302	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	6	6	6	6	6	6	6	6	6	60.0	0.01	0.01	0.01	0.06	0.08	43	0.01
40' MANLIFT	100%	1736	JLG 400S Telescopic Boom Lift	49	Diesel	2	2	2	8	8	8	8	6	6	6	6	6	68.0	0.03	0.02	0.02	0.11	0.10	13	0.00
60' MANLIFT	100%	868	JLG 600S Telescopic Boom Lift	49	Diesel				4	4	4	4	4	4	4	4	4	36.0	0.01	0.01	0.01	0.05	0.05	6	0.00
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.02	0.02	0.02	0.06	0.16	64	0.01
TRACTOR/40' FLOAT	20%	43.4	Mack Truck Pinnacle Series	505	Diesel	2	2	2	1	1	1	1	1	1	1	1	1	15.0	0.00	0.00	0.00	0.00	0.01	1	0.00
UTILITY CARTS (SITE TRANSP)	10%	151.9	John Deere HPX 4 x 4	21	Gas	2	2	2	7	7	7	7	7	7	7	7	6	68.0	0.00	0.00	0.00	0.01	0.01	1	0.00
B - EARTH MOVING																									
580 BACKHOE	100%	434	Case 580N	78	Diesel	2	2	2	2	2	2	2	2	2				18.0	0.01	0.01	0.01	0.05	0.04	6	0.00
225 TRACK HOE	100%	434	Case CX210C	160	Diesel	2	2	2	2	2	2	2	2	2				18.0	0.01	0.01	0.01	0.03	0.05	8	0.00
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	0	Case 885B	214	Diesel								1	1				2.0	0.00	0.00	0.00	0.00	0.00	0	0.00
BOBCAT	30%	65.1	Bobcat S130 Skid Steer Loader	49	Diesel	1	1	1	1	1	1	1	1	1				9.0	0.00	0.00	0.00	0.00	0.00	0	0.00
DITCH WITCH	10%	21.7	Bobcat E32	33.3	Diesel			1	1	1	1	1	1					6.0	0.00	0.00	0.00	0.00	0.00	0	0.00
GAS TAMPER	25%	108.5	Jumping Jack Tamper 115-130LB	4	Gas		2	2	2	2	2	2	2	2				16.0	0.01	0.00	0.00	0.07	0.00	0	0.00
PLATE COMPACTORS	25%	217	Central Machinery 91762	6.5	Gas		4	4	4	4	4	4	4	4				32.0	0.01	0.00	0.00	0.32	0.00	1	0.00
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	1302	Sullair 185	61	Diesel	2	2	2	6	6	6	6	6	6	6	6	6	60.0	0.01	0.01	0.01	0.07	0.14	22	0.00
375 COMPRESSOR	100%	217	Sullair 375HH	139	Diesel	2	2	2	1	1	1	1	1	1	1	1	1	15.0	0.00	0.00	0.00	0.01	0.03	7	0.00
D - HEAVY EQUIP																									
MODULE SET/HEAVY LIFT CRANE	10%	43.4	Manitowac 31000	600	Diesel				2	2	2	2	2	2	2	2	2	18.0	0.00	0.00	0.00	0.01	0.02	4	0.00
220-T CRAWLER	100%	868	Manitowac 14000	340	Diesel				4	4	4	4	4	4	4	4	4	36.0	0.03	0.03	0.03	0.13	0.49	90	0.02
80-TON PICKER	100%	651	Grove RT880E	275	Diesel	2	2	2	3	3	3	3	3	3	3	3	3	33.0	0.01	0.01	0.01	0.02	0.09	55	0.01
35-TON PICKER	100%	0	Grove RT530E-2	164	Diesel							2	2	2	2	2	2	12.0	0.00	0.00	0.00	0.00	0.00	0	0.00
25-TON PICKER	100%	651	Grove YB7725	130	Diesel	3	3	3	3	3	3	8	8	8	5	5	5	57.0	0.01	0.01	0.01	0.02	0.06	36	0.01
8-TON CARRY DECK	100%	0	Grove YB4400	100	Diesel							2	2	2	2	2	2	12.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel	2	2	2										6.0	0.00	0.00	0.00	0.00	0.00	0	0.00
F - PUMP EQUIP																									
2" CENT. PUMPS	5%	43.4	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	4	4	4	4	4	4	4	4	4	48.0	0.00	0.00	0.00	0.08	0.00	0	0.00
TEST PUMPS	100%	0	Air Operated	N/A	Air							2	2	2				6.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																									
RIG WELD TRUCK	100%	868	Electric Driven	N/A	Electric		4	4	4	4	4	12	11	10	8	8	8	77.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8-PAC WELDER'S	100%	0	Lincoln Classic 300D Engine Driven Weld Machine	32.7	Diesel							4	4	4	4	4	4	24.0	0.00	0.00	0.00	0.00	0.00	0	0.00
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	1302	Honda EM5000S	11.7	Gas	4	4	4	6	6	6	10	10	10	6	6	6	78.0	0.07	0.00	0.00	4.13	0.03	15	0.00
Total																			***0.43***	***0.35***	***0.34***	***5.78***	***2.89***	***1010***	***0.17***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.8 - Phase III LNG Tank Construction Emissions - Year 2017

Magnolia LNG Project

Construction Equipment Utilization Matrix

Balance of Plant: All Disciplines

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year										Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7	8	9	10		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																							
PICK-UP TRUCK or VAN newer then 2010	10%	151.9	GMC 1500	250	Diesel	8	8	7	7	7	7	7	7	7	7	72.0	20.42	19.62	19.03	23.53	91.28	77,315	12.08
A - ROLLING EQUIP																							
2-T FLATBED TRUCK	50%	217	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	2	2	2	2	2	20.0	20.42	19.62	19.03	23.53	91.28	77,315	12.08
DUMP TRUCK 6CY	100%	0	Mack Truck Granite Series	415	Diesel	Not Used										0.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
FARM TRACTOR w/TRAILER	100%	434	Kubota L4240	44	Diesel	2	2	2	2	2	2	2	2	2	2	20.0	3.15	3.37	3.27	15.69	39.25	6,747	1.26
CEMENT TRUCK	15%	0	Mack Truck Granite Series	415	Diesel	Not Used										0.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
CEMENT PUMP TRUCK	100%	0	Putzmeister 70Z-Meter	450	Diesel	Not Used										0.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
FUEL TRUCK	30%	65.1	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
MECH TRUCK	2%	4.34	GMC 1500	250	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	20.42	19.62	19.03	23.53	91.28	77,315	12.08
BUS	1%	2.17	Blue Bird Vision	260	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	27.56	27.66	26.83	93.98	279.40	73,936	13.50
SCISSOR LIFT	50%	217	Electric Operated	N/A	Electric	2	2	2	2	2	2	2	2	2	2	20.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EXTEND-A-FORKLIFT	100%	1302	JLG 8042 Sky Trak Telehandler	100	Diesel	6	6	6	6	6	6	6	4	2	2	50.0	7.25	8.81	8.54	31.48	36.80	30,044	4.74
40' MANLIFT	100%	1736	JLG 400S Telescopic Boom Lift	49	Diesel	8	8	8	8	8	8	8	8	4	2	70.0	14.00	8.07	7.82	51.94	50.18	6,602	1.32
60' MANLIFT	100%	868	JLG 600S Telescopic Boom Lift	49	Diesel	4	4	4	4	4	4	4	4	3	2	37.0	14.00	8.07	7.82	51.94	50.18	6,602	1.32
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	20.0	36.34	38.53	37.38	92.23	262.71	132,885	21.86
TRACTOR/40' FLOAT	20%	43.4	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	22.02	16.71	16.21	74.14	144.77	26,248	5.02
UTILITY CARTS (SITE TRANSP)	10%	108.5	John Deere HPX 4 x 4	21	Gas	6	6	5	5	5	5	5	5	5	5	52.0	5.89	4.52	4.38	29.88	55.49	7,404	1.59
B - EARTH MOVING																							
580 BACKHOE	100%	0	Case 580N	78	Diesel	Not Used										0.0	14.62	14.03	13.61	89.60	72.13	12,696	2.47
225 TRACK HOE	100%	0	Case CX210C	160	Diesel	Not Used										0.0	14.96	12.42	12.04	54.10	92.73	15,836	3.08
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	0	Case 885B	214	Diesel	Not Used										0.0	21.82	22.77	22.09	55.54	169.94	73,162	12.36
BOBCAT	30%	0	Bobcat S130 Skid Steer Loader	49	Diesel	Not Used										0.0	5.58	4.92	4.77	25.52	41.91	6,552	1.26
DITCH WITCH	10%	0	Bobcat E32	33.3	Diesel	Not Used										0.0	2.22	2.37	2.30	11.03	27.59	4,742	0.88
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used										0.0	121.37	19.12	17.59	578.84	2.73	1,435	0.29
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas	Not Used										0.0	20.49	0.52	0.48	1,325.03	7.76	4,734	0.98
C - AIR OP EQUIP																							
185 COMPRESSOR	100%	1302	Sullair 185	61	Diesel	6	6	6	6	6	6	6	4	2	1	49.0	6.89	7.30	7.08	44.22	95.93	15,404	2.94
375 COMPRESSOR	100%	217	Sullair 375HH	139	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	11.93	11.35	11.01	32.47	123.85	29,466	5.50
D - HEAVY EQUIP																							
MODULE SET/HEAVY LIFT CRANE	10%	0	Manitowac 31000	600	Diesel	2	2									4.0	32.90	29.35	28.47	118.31	457.62	93,980	17.66
220-T CRAWLER	100%	0	Manitowac 14000	340	Diesel	4	4									8.0	32.90	29.35	28.47	118.31	457.62	93,980	17.66
80-TON PICKER	100%	651	Grove RT880E	275	Diesel	3	3	3	3	3	3					18.0	20.42	19.62	19.03	23.53	91.28	77,315	12.08
35-TON PICKER	100%	434	Grove RT530E-2	164	Diesel	2	2	2	2	2	2	2				14.0	13.62	14.33	13.90	22.60	63.89	50,794	8.04
25-TON PICKER	100%	1085	Grove YB7725	130	Diesel	5	5	5	5	5	5	5	3	3		41.0	13.62	14.33	13.90	22.60	63.89	50,794	8.04
8-TON CARRY DECK	100%	434	Grove YB4400	100	Diesel	2	2	2	2	2	2	2	2	2		18.0	8.29	10.39	10.08	51.49	83.03	22,350	4.08
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel											0.0	56.26	61.29	59.45	336.86	784.31	140,014	26.78
F - PUMP EQUIP																							
2" CENT. PUMPS	5%	43.4	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	4	4	4	4	4			32.0	25.96	0.68	0.63	1,684.17	9.48	6,019	1.24
TEST PUMPS	100%	434	Air Operated	N/A	Air			2	2	2	2	2	2			12.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																							
RIG WELD TRUCK	100%	1736	Electric Driven	N/A	Electric	8	8	8	8	8	8	6	4	2		60.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8-PAC WELDER'S	100%	868	Lincoln Classic 300D	32.7	Diesel	4	4	4	4	4	4	4	3	2		33.0	5.86	4.42	4.29	24.86	32.70	4,803	0.94
I - ELECTRICAL EQUIP																							
GENERATOR'S 5KW	100%	1302	Honda EM5000S	11.7	Gas	6	6	6	6	6	6	6	4	2		48.0	44.53	1.10	1.01	2,859.98	17.19	10,206	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2017 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year										Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7	8	9	10		VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
SK TRUCKS & CARS																							
PICK-UP TRUCK or VAN newer then 2010	10%	151.9	GMC 1500	250	Diesel	8	8	7	7	7	7	7	7	7	7	72.0	0.00	0.00	0.00	0.00	0.02	13	0.00
A - ROLLING EQUIP																							
2-T FLATBED TRUCK	50%	217	Chevrolet Kodiak C5500	300	Diesel	2	2	2	2	2	2	2	2	2	2	20.0	0.00	0.00	0.00	0.01	0.02	18	0.00
DUMP TRUCK 6CY	100%	0	Mack Truck Granite Series	415	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
FARM TRACTOR w/TRAILER	100%	434	Kubota L4240	44	Diesel	2	2	2	2	2	2	2	2	2	2	20.0	0.00	0.00	0.00	0.01	0.02	3	0.00
CEMENT TRUCK	15%	0	Mack Truck Granite Series	415	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
CEMENT PUMP TRUCK	100%	0	Putzmeister 70Z-Meter	450	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
FUEL TRUCK	30%	65.1	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	0.00	0.00	0.00	0.01	0.02	10	0.00
MECH TRUCK	2%	4.34	GMC 1500	250	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	0.00	0.00	0.00	0.00	0.00	0	0.00
BUS	1%	2.17	Blue Bird Vision	260	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	0.00	0.00	0.00	0.00	0.00	0	0.00
SCISSOR LIFT	50%	217	Electric Operated	N/A	electric	2	2	2	2	2	2	2	2	2	2	20.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EXTEND-A-FORKLIFT	100%	1302	JLG 8042 Sky Trak Telehandler	100	Diesel	6	6	6	6	6	6	6	4	2	2	50.0	0.01	0.01	0.01	0.05	0.05	43	0.01
40' MANLIFT	100%	1736	JLG 400S Telescopic Boom Lift	49	Diesel	8	8	8	8	8	8	8	8	4	2	70.0	0.03	0.02	0.01	0.10	0.10	13	0.00
60' MANLIFT	100%	868	JLG 600S Telescopic Boom Lift	49	Diesel	4	4	4	4	4	4	4	4	3	2	37.0	0.01	0.01	0.01	0.05	0.05	6	0.00
1-T STAKEBED TRUCK	100%	434	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	20.0	0.02	0.02	0.02	0.04	0.13	64	0.01
TRACTOR/40' FLOAT	20%	43.4	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	0.00	0.00	0.00	0.00	0.01	1	0.00
UTILITY CARTS (SITE TRANSP)	10%	108.5	John Deere HPX 4 x 4	21	Gas	6	6	5	5	5	5	5	5	5	5	52.0	0.00	0.00	0.00	0.00	0.01	1	0.00
B - EARTH MOVING																							
580 BACKHOE	100%	0	Case 580N	78	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
225 TRACK HOE	100%	0	Case CX210C	160	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
GRADER FINAL DRESS UP BEFORE ASPHALT	10%	0	Case 885B	214	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
BOBCAT	30%	0	Bobcat S130 Skid Steer Loader	49	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
DITCH WITCH	10%	0	Bobcat E32	33.3	Diesel	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
GAS TAMPER	25%	0	Jumping Jack Tamper 115-130LB	4	Gas	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
PLATE COMPACTORS	25%	0	Central Machinery 91762	6.5	Gas	Not Used										0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
C - AIR OP EQUIP																							
185 COMPRESSOR	100%	1302	Sullair 185	61	Diesel	6	6	6	6	6	6	6	4	2	1	49.0	0.01	0.01	0.01	0.06	0.14	22	0.00
375 COMPRESSOR	100%	217	Sullair 375HH	139	Diesel	1	1	1	1	1	1	1	1	1	1	10.0	0.00	0.00	0.00	0.01	0.03	7	0.00
D - HEAVY EQUIP																							
MODULE SET/HEAVY LIFT CRANE	10%	0	Manitowac 31000	600	Diesel	2	2									4.0	0.00	0.00	0.00	0.00	0.00	0	0.00
220-T CRAWLER	100%	0	Manitowac 14000	340	Diesel	4	4									8.0	0.00	0.00	0.00	0.00	0.00	0	0.00
80-TON PICKER	100%	651	Grove RT880E	275	Diesel	3	3	3	3	3	3					18.0	0.01	0.01	0.01	0.02	0.07	55	0.01
35-TON PICKER	100%	434	Grove RT530E-2	164	Diesel	2	2	2	2	2	2	2				14.0	0.01	0.01	0.01	0.01	0.03	24	0.00
25-TON PICKER	100%	1085	Grove YB7725	130	Diesel	5	5	5	5	5	5	5	3	3		41.0	0.02	0.02	0.02	0.03	0.08	61	0.01
8-TON CARRY DECK	100%	434	Grove YB4400	100	Diesel	2	2	2	2	2	2	2	2	2		18.0	0.00	0.00	0.00	0.02	0.04	11	0.00
PILE DRIVER	100%	0	Delmag D46-32/33	350	Diesel											0.0	0.00	0.00	0.00	0.00	0.00	0	0.00
F - PUMP EQUIP																							
2" CENT. PUMPS	5%	43.4	DuroMax Portable 2" Water Pump	7	Gas	4	4	4	4	4	4	4	4			32.0	0.00	0.00	0.00	0.08	0.00	0	0.00
TEST PUMPS	100%	434	Air Operated	N/A	air			2	2	2	2	2	2			12.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
G - WELDING EQUIP																							
RIG WELD TRUCK	100%	1736	Electric Driven	N/A	electric	8	8	8	8	8	8	6	4	2		60.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8-PAC WELDER'S	100%	868	Lincoln Classic 300D	32.7	Diesel	4	4	4	4	4	4	4	3	2		33.0	0.01	0.00	0.00	0.02	0.03	5	0.00
I - ELECTRICAL EQUIP																							
GENERATOR'S 5KW	100%	1302	Honda EM5000S	11.7	Gas	6	6	6	6	6	6	6	4	2		48.0	0.06	0.00	0.00	4.10	0.02	15	0.00
																Total	***0.21***	***0.13***	***0.13***	***4.63***	***0.85***	***372***	***0.06***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.9 - Phase IV Architectural - Year 2016

Magnolia LNG Project

Construction Equipment Utilization Matrix

Architectural Buildings

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year								Equipment Months	NONROAD Emission Factor (gram/hr)						
						5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																					
PICK-UP TRUCK or VAN newer then 2010	10%	347.2	GMC 1500	250	Gas	2	2	2	2	2	2	2	2	16.0	20.75	20.35	19.74	29.24	123.79	77,314.33	12.23
A - ROLLING EQUIP																					
2-T FLATBED TRUCK	50%	868	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	8.0	20.75	20.35	19.74	29.24	123.79	77,314.33	12.23
DUMP TRUCK 6CY	10%	65.1	Mack Truck Granite Series	415	Diesel	1	1	1						3.0	37.38	41.84	40.59	123.72	329.59	132,881.78	22.63
FORKLIFT	25%	434	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	1	8.0	7.48	10.14	9.83	41.50	52.52	30,043.46	4.84
EXTEND-A-FORKLIFT	100%	3472	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	2	2	2	2	16.0	7.48	10.14	9.83	41.50	52.52	30,043.46	4.84
CEMENT TRUCK	2%	208.32	Mack Truck Granite Series	415	Diesel	16	16	16						48.0	37.38	41.84	40.59	123.72	329.59	132,881.78	22.63
CEMENT PUMP TRUCK	100%	651	Putzmeister 70Z-Meter	450	Diesel	1	1	1						3.0	37.38	41.84	40.59	123.72	329.59	132,881.78	22.63
FUEL TRUCK	15%	260.4	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	8.0	37.38	41.84	40.59	123.72	329.59	132,881.78	22.63
MECH TRUCK	2%	34.72	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	8.0	20.75	20.35	19.74	29.24	123.79	77,314.33	12.23
SCISSOR LIFT	100%	6944	JLG 3394RT Scissor Lift	82	Gas	4	4	4	4	4	4	4	4	32.0	115.8244	2.026913	1.86476	3982.1333	250.2594	22564.84811	4.6492
40' MANLIFT	100%	2170	JLG 400S Telescopic Boom Lift	49	Diesel				2	2	2	2	2	10.0	15.24	8.56	8.30	56.07	51.77	6,598.27	1.34
TRACTOR/40' FLOAT	10%	173.6	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	1	8.0	23.79	17.71	17.18	81.06	158.04	26,242.76	5.10
B - EARTH MOVING																					
450 CASE DOZER	25%	162.75	Case 650L	74	Diesel	1	1	1						3.0	6.92	8.63	8.38	60.52	110.47	20,372.52	3.81
580 BACKHOE	25%	162.75	Case 580N	78	Diesel	1	1	1						3.0	16.17	15.11	14.66	96.80	78.44	12,691.77	2.51
225 TRACK HOE	25%	162.75	Case CX210C	160	Diesel	1	1	1						3.0	16.19	13.12	12.72	59.05	101.17	15,831.97	3.13
DITCH WITCH	10%	65.1	Bobcat E32	33.3	Diesel	1	1	1						3.0	2.63	2.75	2.66	13.29	28.93	4,740.77	0.91
C - AIR OP EQUIP																					
185 COMPRESSOR	100%	3472	Sullair 185	61	Diesel	2	2	2	2	2	2	2	2	16.0	7.57	7.88	7.64	48.59	99.84	15,401.54	3.01
D - HEAVY EQUIP																					
25-TON PICKER	100%	2170	Grove YB7725	130	Diesel				2	2	2	2	2	10.0	14.01	16.01	15.53	30.48	88.38	50,792.76	8.22
G - WELDING EQUIP																					
8-PAC WELDER'S	10%	108.5	Electric Driven	N/A	Electric				1	1	1	1	1	5.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																					
GENERATOR'S 5KW	100%	5642	Honda EM5000S	11.7	Gas	2	2	2	4	4	4	4	4	26.0	45.91	1.10	1.01	2,875.10	18.19	10,204.61	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2016 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year								Equipment Months	Annual Emission (ton)						
						5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																					
PICK-UP TRUCK or VAN newer then 2010	10%	347.2	GMC 1500	250	Gas	2	2	2	2	2	2	2	2	16.0	0.01	0.01	0.01	0.01	0.05	29.59	0.00
A - ROLLING EQUIP																					
2-T FLATBED TRUCK	50%	868	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	8.0	0.02	0.02	0.02	0.03	0.12	73.97	0.01
DUMP TRUCK 6CY	10%	65.1	Mack Truck Granite Series	415	Diesel	1	1	1						3.0	0.00	0.00	0.00	0.01	0.02	9.54	0.00
FORKLIFT	25%	434	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	1	8.0	0.00	0.00	0.00	0.02	0.03	14.37	0.00
EXTEND-A-FORKLIFT	100%	3472	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	2	2	2	2	16.0	0.03	0.04	0.04	0.16	0.20	114.98	0.02
CEMENT TRUCK	2%	208.32	Mack Truck Granite Series	415	Diesel	16	16	16						48.0	0.01	0.01	0.01	0.03	0.08	30.51	0.01
CEMENT PUMP TRUCK	100%	651	Putzmeister 70Z-Meter	???	Diesel	1	1	1						3.0	0.03	0.03	0.03	0.09	0.24	95.36	0.02
FUEL TRUCK	15%	260.4	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	8.0	0.01	0.01	0.01	0.04	0.09	38.14	0.01
MECH TRUCK	2%	34.72	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	8.0	0.00	0.00	0.00	0.00	0.00	2.96	0.00
SCISSOR LIFT	100%	6944	JLG 3394RT Scissor Lift	82	Gas	4	4	4	4	4	4	4	4	32.0	0.89	0.02	0.01	30.48	1.92	172.72	0.04
40' MANLIFT	100%	2170	JLG 400S Telescopic Boom Lift	49	Diesel				2	2	2	2	2	10.0	0.04	0.02	0.02	0.13	0.12	15.78	0.00
TRACTOR/40' FLOAT	10%	173.6	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	1	8.0	0.00	0.00	0.00	0.02	0.03	5.02	0.00
B - EARTH MOVING																					
450 CASE DOZER	25%	162.75	Case 650L	74	Diesel	1	1	1						3.0	0.00	0.00	0.00	0.01	0.02	3.65	0.00
580 BACKHOE	25%	162.75	Case 580N	78	Diesel	1	1	1						3.0	0.00	0.00	0.00	0.02	0.01	2.28	0.00
225 TRACK HOE	25%	162.75	Case CX210C	160	Diesel	1	1	1						3.0	0.00	0.00	0.00	0.01	0.02	2.84	0.00
DITCH WITCH	10%	65.1	Bobcat E32	33.3	Diesel	1	1	1						3.0	0.00	0.00	0.00	0.00	0.00	0.34	0.00
C - AIR OP EQUIP																					
185 COMPRESSOR	100%	3472	Sullair 185	61	Diesel	2	2	2	2	2	2	2	2	16.0	0.03	0.03	0.03	0.19	0.38	58.95	0.01
D - HEAVY EQUIP																					
25-TON PICKER	100%	2170	Grove YB7725	130	Diesel				2	2	2	2	2	10.0	0.03	0.04	0.04	0.07	0.21	121.50	0.02
G - WELDING EQUIP																					
8-PAC WELDER'S	10%	108.5	Electric Driven	N/A	Electric				1	1	1	1	1	5.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																					
GENERATOR'S 5KW	100%	5642	Honda EM5000S	11.7	Gas	2	2	2	4	4	4	4	4	26.0	0.29	0.01	0.01	17.88	0.11	63.46	0.01
														Total	***1.39***	***0.25***	***0.24***	***49.19***	***3.66***	***855.97***	***0.15***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.10 - Phase IV Architectural - Year 2017

Magnolia LNG Project

Construction Equipment Utilization Matrix

Architectural Buildings

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year							Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																				
PICK-UP TRUCK or VAN newer then 2010	10%	303.8	GMC 1500	250	Gas	2	2	2	2	2	2	2	14.0	13.62	14.33	13.90	22.60	63.89	50,793.94	8.04
A - ROLLING EQUIP																				
2-T FLATBED TRUCK	50%	759.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	7.0	13.62	14.33	13.90	22.60	63.89	50,793.94	8.04
DUMP TRUCK 6CY	10%	0	Mack Truck Granite Series	415	Diesel	Not Used							0.0	36.34	38.53	37.38	92.23	262.71	132,884.93	21.86
FORKLIFT	25%	379.75	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	7.0	7.25	8.81	8.54	31.48	36.80	30,044.17	4.74
EXTEND-A-FORKLIFT	100%	3038	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	2	2	2	14.0	7.25	8.81	8.54	31.48	36.80	30,044.17	4.74
CEMENT TRUCK	2%	0	Mack Truck Granite Series	415	Diesel	Not Used							0.0	36.34	38.53	37.38	92.23	262.71	132,884.93	21.86
CEMENT PUMP TRUCK	100%	0	Putzmeister 70Z-Meter	???	Diesel	Not Used							0.0	36.34	38.53	37.38	92.23	262.71	132,884.93	21.86
FUEL TRUCK	15%	227.85	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	7.0	36.34	38.53	37.38	92.23	262.71	132,884.93	21.86
MECH TRUCK	2%	30.38	GMC 1500	250	Gas	1	1	1	1	1	1	1	7.0	20.42	19.62	19.03	23.53	91.28	77,315.36	12.08
SCISSOR LIFT	100%	6076	JLG 3394RT Scissor Lift	82	Gas	4	4	4	4	4	4	4	28.0	113.42	2.03	1.87	3,909.01	244.50	22,456.27	4.63
40' MANLIFT	100%	0	JLG 400S Telescopic Boom Lift	49	Diesel	Not Used							0.0	14.00	8.07	7.82	51.94	50.18	6,602.02	1.32
TRACTOR/40' FLOAT	10%	151.9	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	7.0	22.02	16.71	16.21	74.14	144.77	26,248.14	5.02
B - EARTH MOVING																				
450 CASE DOZER	25%	0	Case 650L	74	Diesel	Not Used							0.0	6.37	7.94	7.70	51.43	108.16	20,374.18	3.69
580 BACKHOE	25%	0	Case 580N	78	Diesel	Not Used							0.0	14.62	14.03	13.61	89.60	72.13	12,696.45	2.47
225 TRACK HOE	25%	0	Case CX210C	160	Diesel	Not Used							0.0	14.96	12.42	12.04	54.10	92.73	15,835.68	3.08
DITCH WITCH	10%	0	Bobcat E32	33.3	Diesel	Not Used							0.0	2.22	2.37	2.30	11.03	27.59	4,742.02	0.88
C - AIR OP EQUIP																				
185 COMPRESSOR	100%	3038	Sullair 185	61	Diesel	2	2	2	2	2	2	2	14.0	6.89	7.30	7.08	44.22	95.93	15,403.60	2.94
D - HEAVY EQUIP																				
25-TON PICKER	100%	3038	Grove YB7725	130	Diesel	2	2	2	2	2	2	2	14.0	13.62	14.33	13.90	22.60	63.89	50,793.94	8.04
G - WELDING EQUIP																				
8-PAC WELDER'S	10%	108.5	Electric Driven	N/A	Electric	1	1	1	1	1			5.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																				
GENERATOR'S 5KW	100%	6076	Honda EM5000S	11.7	Gas	4	4	4	4	4	4	4	28.0	44.53	1.10	1.01	2,859.98	17.19	10,206.02	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2017 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year							Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																				
PICK-UP TRUCK or VAN newer then 2010	10%	303.8	GMC 1500	250	Gas	2	2	2	2	2	2	2	14.0	0.00	0.00	0.00	0.01	0.02	17.01	0.00
A - ROLLING EQUIP																				
2-T FLATBED TRUCK	50%	759.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	7.0	0.01	0.01	0.01	0.02	0.05	42.52	0.01
DUMP TRUCK 6CY	10%	0	Mack Truck Granite Series	415	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FORKLIFT	25%	379.75	Cat PD10000	77	Diesel	1	1	1	1	1	1	1	7.0	0.00	0.00	0.00	0.01	0.02	12.58	0.00
EXTEND-A-FORKLIFT	100%	3038	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	2	2	2	14.0	0.02	0.03	0.03	0.11	0.12	100.61	0.02
CEMENT TRUCK	2%	0	Mack Truck Granite Series	415	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CEMENT PUMP TRUCK	100%	0	Putzmeister 70Z-Meter	???	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL TRUCK	15%	227.85	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	7.0	0.01	0.01	0.01	0.02	0.07	33.38	0.01
MECH TRUCK	2%	30.38	GMC 1500	250	Gas	1	1	1	1	1	1	1	7.0	0.00	0.00	0.00	0.00	0.00	2.59	0.00
SCISSOR LIFT	100%	6076	JLG 3394RT Scissor Lift	82	Gas	4	4	4	4	4	4	4	28.0	0.76	0.01	0.01	26.18	1.64	150.40	0.03
40' MANLIFT	100%	0	JLG 400S Telescopic Boom Lift	49	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TRACTOR/40' FLOAT	10%	151.9	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	7.0	0.00	0.00	0.00	0.01	0.02	4.40	0.00
B - EARTH MOVING																				
450 CASE DOZER	25%	0	Case 650L	74	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
580 BACKHOE	25%	0	Case 580N	78	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
225 TRACK HOE	25%	0	Case CX210C	160	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DITCH WITCH	10%	0	Bobcat E32	33.3	Diesel	Not Used							0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C - AIR OP EQUIP																				
185 COMPRESSOR	100%	3038	Sullair 185	61	Diesel	2	2	2	2	2	2	2	14.0	0.02	0.02	0.02	0.15	0.32	51.58	0.01
D - HEAVY EQUIP																				
25-TON PICKER	100%	3038	Grove YB7725	130	Diesel	2	2	2	2	2	2	2	14.0	0.05	0.05	0.05	0.08	0.21	170.10	0.03
G - WELDING EQUIP																				
8-PAC WELDER'S	10%	108.5	Electric Driven	N/A	Electric	1	1	1	1	1			5.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																				
GENERATOR'S 5KW	100%	6076	Honda EM5000S	11.7	Gas	4	4	4	4	4	4	4	28.0	0.30	0.01	0.01	19.16	0.12	68.36	0.01
													Total	***1.18***	***0.16***	***0.15***	***45.74***	***2.59***	***653.53***	***0.12***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.11 - Phase V Marine Work - Year 2015

Magnolia LNG Project

Construction Equipment Utilization Matrix

Marine Work

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year			Equipment Months	NONROAD Emission Factor (gram/hr)						
						10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																
PICK-UP TRUCK or VAN newer then 2010	10%	130.2	GMC 1500	250	Diesel	2	2	2	6.0	21.36	21.66	21.01	39.51	163.59	77312	12.52
A - ROLLING EQUIP																
2-T FLATBED TRUCK	50%	325.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	3.0	21.36	21.66	21.01	39.51	163.59	77312	12.52
DUMP TRUCK 14CY	100%	1302	Mack Truck Granite Series	415	Diesel	2	2	2	6.0	38.53	45.09	43.74	157.72	403.14	132878	23.48
FARM WAGON w/TRAILER	100%	0	Kubota L4240	44	Diesel	Not Used			0.0	4.43	4.49	4.35	22.50	43.22	6744	1.33
FUEL TRUCK	30%	195.3	Chevrolet C3500	397	Diesel	1	1	1	3.0	38.53	45.09	43.74	157.72	403.14	132878	23.48
MECH TRUCK	2%	13.02	GMC 1500	250	Diesel	1	1	1	3.0	21.36	21.66	21.01	39.51	163.59	77312	12.52
EXTEND-A-FORKLIFT	100%	0	JLG 8042 Sky Trak Telehandler	100	Diesel	Not Used			0.0	8.09	13.66	13.25	68.35	76.56	30042	5.10
1-T STAKEBED TRUCK	50%	651	Chevrolet C3500	397	Diesel	2	2	2	6.0	38.53	45.09	43.74	157.72	403.14	132878	23.48
TRACTOR/40' FLOAT	10%	65.1	Mack Truck Pinnacle Series	505	Diesel	1	1	1	3.0	25.74	18.79	18.23	88.89	172.15	26237	5.18
UTILITY CARTS (SITE TRANSP)	10%	130.2	John Deere HPX 4 x 4	21	Gas	2	2	2	6.0	41.74	0.99	0.91	2,558.85	16.59	9039	1.86
B - EARTH MOVING																
DREDGER	100%	651	Typical	1450	Diesel	1	1	1	3.0	291.87	324.3	324.3	2702.5	14053	754765.01	1405.3
580 BACKHOE	100%	651	Case 580N	78	Diesel	1	1	1	3.0	17.81	16.23	15.74	104.35	85.04	12687	2.55
225 TRACK HOE	100%	1302	Case CX210C	160	Diesel	2	2	2	6.0	17.72	13.94	13.52	65.90	110.85	15827	3.18
EXTEND-A-HOE	100%	1302	Case CX210C	161	Diesel	2	2	2	6.0	17.72	13.94	13.52	65.90	110.85	15827	3.18
C - AIR OP EQUIP																
185 COMPRESSOR	100%	0	Sullair 185	61	Diesel	Not Used			0.0	8.31	8.49	8.24	53.16	104.09	15399	3.08
D - HEAVY EQUIP																
300-T CRAWLER	100%	0	Manitowac 2250	500	Diesel	Not Used			0.0	38.53	45.09	43.74	157.72	403.14	132878	23.48
80-TON PICKER	100%	0	Manitowac 2250	500	Diesel	Not Used			0.0	38.53	45.09	43.74	157.72	403.14	132878	23.48
35-TON PICKER	100%	0	Grove RT530E-2	164	Diesel	Not Used			0.0	14.99	19.99	19.39	49.19	124.67	50790	8.67
25-TON PICKER	100%	0	Grove YB7725	130	Diesel	Not Used			0.0	14.99	19.99	19.39	49.19	124.67	50790	8.67
G - WELDING EQUIP																
8-PAC WELDER'S	100%	0	Electric Driven	N/A	Electric				0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																
GENERATOR'S 5KW	100%	0	Honda EM5000S	11.7	Gas				0.0	48.75	1.10	1.01	2,906.80	20.29	10202	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.
Dredge will be vessel mounted. Assumed hp of vessel 1,450 hp, typical "Jekyll Island" vessel.
Note: Pile driver for installation of steel sheet pile bulkhead, five breasting dolphins using steel pilings and other plant pilings accounted for under Balance of Plant Phase.

2015 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year			Equipment Months	Annual Emission (ton)						
						10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																
PICK-UP TRUCK or VAN newer then 2010	10%	130.2	GMC 1500	250	Diesel	2	2	2	6.0	0.00	0.00	0.00	0.01	0.02	11.10	0.00
A - ROLLING EQUIP																
2-T FLATBED TRUCK	50%	325.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	3.0	0.01	0.01	0.01	0.01	0.06	27.74	0.00
DUMP TRUCK 14CY	100%	1302	Mack Truck Granite Series	415	Diesel	2	2	2	6.0	0.06	0.06	0.06	0.23	0.58	190.71	0.03
FARM WAGON w/TRAILER	100%	0	Kubota L4240	44	Diesel	Not Used			0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL TRUCK	30%	195.3	Chevrolet C3500	397	Diesel	1	1	1	3.0	0.01	0.01	0.01	0.03	0.09	28.61	0.01
MECH TRUCK	2%	13.02	GMC 1500	250	Diesel	1	1	1	3.0	0.00	0.00	0.00	0.00	0.00	1.11	0.00
EXTEND-A-FORKLIFT	100%	0	JLG 8042 Sky Trak Telehandler	100	Diesel	Not Used			0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1-T STAKEBED TRUCK	50%	651	Chevrolet C3500	397	Diesel	2	2	2	6.0	0.03	0.03	0.03	0.11	0.29	95.35	0.02
TRACTOR/40' FLOAT	10%	65.1	Mack Truck Pinnacle Series	505	Diesel	1	1	1	3.0	0.00	0.00	0.00	0.01	0.01	1.88	0.00
UTILITY CARTS (SITE TRANSP)	10%	130.2	John Deere HPX 4 x 4	21	Gas	2	2	2	6.0	0.01	0.00	0.00	0.37	0.00	1.30	0.00
B - EARTH MOVING																
DREDGER	100%	651	Typical	1450	Diesel	1	1	1	3.0	0.21	0.23	0.23	1.94	10.08	541.62	1.01
580 BACKHOE	100%	651	Case 580N	78	Diesel	1	1	1	3.0	0.01	0.01	0.01	0.07	0.06	9.10	0.00
225 TRACK HOE	100%	1302	Case CX210C	160	Diesel	2	2	2	6.0	0.03	0.02	0.02	0.09	0.16	22.72	0.00
EXTEND-A-HOE	100%	1302	Case CX210C	161	Diesel	2	2	2	6.0	0.03	0.02	0.02	0.09	0.16	22.72	0.00
C - AIR OP EQUIP																
185 COMPRESSOR	100%	0	Sullair 185	61	Diesel	Not Used			0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
D - HEAVY EQUIP																
300-T CRAWLER	100%	0	Manitowac 2250	500	Diesel	Not Used			0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
80-TON PICKER	100%	0	Manitowac 2250	500	Diesel	Not Used			0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35-TON PICKER	100%	0	Grove RT530E-2	164	Diesel	Not Used			0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25-TON PICKER	100%	0	Grove YB7725	130	Diesel	Not Used			0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
G - WELDING EQUIP																
8-PAC WELDER'S	100%	0	Electric Driven	N/A	Electric				0.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																
GENERATOR'S 5KW	100%	0	Honda EM5000S	11.7	Gas				0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
									Total	***0.38***	***0.40***	***0.40***	***2.97***	***11.52***	***953.95***	***1.08***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.12 Phase V Marine Work - Year 2016

Magnolia LNG Project

Construction Equipment Utilization Matrix

Marine Work

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	520.8	GMC 1500	250	Gas	2	2	2	2	2	2	2	2	2	2	2	2	24.0	20.75	20.35	19.74	29.24	123.79	77314.33	12.23
A - ROLLING EQUIP																									
2-T FLATBED TRUCK	50%	1302	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	20.75	20.35	19.74	29.24	123.79	77314.33	12.23
DUMP TRUCK 14CY	100%	868	Mack Truck Granite Series	415	Diesel	2	2											4.0	37.38	41.84	40.59	123.72	329.59	132881.78	22.63
FARM WAGON w/TRAILER	100%	2170	Kubota L4240	44	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	3.74	3.91	3.79	18.92	41.17	6745.63	1.29
FUEL TRUCK	30%	781.2	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	37.38	41.84	40.59	123.72	329.59	132881.78	22.63
MECH TRUCK	2%	52.08	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	1	1	1	1	12.0	20.75	20.35	19.74	29.24	123.79	77314.33	12.23
EXTEND-A-FORKLIFT	100%	4340	JLG 8042 Sky Trak Telehandler	100	Diesel			2	2	2	2	2	2	2	2	2	2	20.0	7.48	10.14	9.83	41.50	52.52	30043.46	4.84
1-T STAKEBED TRUCK	50%	2604	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	37.38	41.84	40.59	123.72	329.59	132881.78	22.63
TRACTOR/40' FLOAT	10%	260.4	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	23.79	17.71	17.18	81.06	158.04	26242.76	5.10
UTILITY CARTS (SITE TRANSP)	10%	520.8	John Deere HPX 4 x 4	21	Gas	2	2	2	2	2	2	2	2	2	2	2	2	24.0	5.91	4.53	4.39	30.24	55.48	7403.65	1.59
B - EARTH MOVING																									
DREDGER	100%	434	Typical	1450	Diesel	1	1											2.0	291.87	324.30	324.30	2702.50	14053.00	754765.01	1405.30
580 BACKHOE	100%	434	Case 580N	78	Diesel	1	1											2.0	16.17	15.11	14.66	96.80	78.44	12691.77	2.51
225 TRACK HOE	100%	868	Case CX210C	160	Diesel	2	2											4.0	16.19	13.12	12.72	59.05	101.17	15831.97	3.13
EXTEND-A-HOE	100%	868	Case CX210C	161	Diesel	2	2											4.0	16.19	13.12	12.72	59.05	101.17	15831.97	3.13
C - AIR OP EQUIP																									
185 COMPRESSOR	100%	4340	Sullair 185	61	Diesel			2	2	2	2	2	2	2	2	2	2	20.0	7.57	7.88	7.64	48.59	99.84	15401.54	3.01
D - HEAVY EQUIP																									
300-T CRAWLER	100%	2170	Manitowac 2250	500	Diesel		1	1	1	1	1	1	1	1	1	1	1	10.0	37.38	41.84	40.59	123.72	329.59	132881.78	22.63
80-TON PICKER	100%	2170	Manitowac 2250	500	Diesel		1	1	1	1	1	1	1	1	1	1	1	10.0	37.38	41.84	40.59	123.72	329.59	132881.78	22.63
35-TON PICKER	100%	2170	Grove RT530E-2	164	Diesel		1	1	1	1	1	1	1	1	1	1	1	10.0	14.01	16.01	15.53	30.48	88.38	50792.76	8.22
25-TON PICKER	100%	4340	Grove YB7725	130	Diesel		2	2	2	2	2	2	2	2	2	2	2	20.0	14.01	16.01	15.53	30.48	88.38	50792.76	8.22
G - WELDING EQUIP																									
8-PAC WELDER'S	100%	4340	Electric Driven	N/A	Electric		2	2	2	2	2	2	2	2	2	2	2	20.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																									
GENERATOR'S 5KW	100%	8680	Honda EM5000S	11.7	Gas		4	4	4	4	4	4	4	4	4	4	4	40.0	45.91	1.10	1.01	2875.10	18.19	10204.61	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.
Dredge will be vessel mounted. Assumed hp of vessel 1,450 hp, typical "Jekyll Island" vessel.
Note: Pile driver for installation of steel sheet pile bulkhead, five breasting dolphins using steel pilings and other plant pilings accounted for under Balance of Plant Phase.

2016 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year											Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7	8	9	10	11	12	VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																								
PICK-UP TRUCK or VAN newer then 2010	10%	520.8	GMC 1500	250	Gas	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.01	0.01	0.01	0.02	0.07	44.38	0.01
A - ROLLING EQUIP																								
2-T FLATBED TRUCK	50%	1302	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.03	0.03	0.03	0.04	0.18	110.96	0.02
DUMP TRUCK 14CY	100%	868	Mack Truck Granite Series	415	Diesel	2	2											4.0	0.04	0.04	0.04	0.12	0.32	127.14	0.02
FARM WAGON w/TRAILER	100%	2170	Kubota L4240	44	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	0.01	0.01	0.01	0.05	0.10	16.14	0.00
FUEL TRUCK	30%	781.2	Chevrolet C3500	397	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.03	0.04	0.03	0.11	0.28	114.43	0.02
MECH TRUCK	2%	52.08	GMC 1500	250	Gas	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.00	0.01	4.44	0.00
EXTEND-A-FORKLIFT	100%	4340	JLG 8042 Sky Trak Telehandler	100	Diesel			2	2	2	2	2	2	2	2	2	2	20.0	0.04	0.05	0.05	0.20	0.25	143.73	0.02
1-T STAKEBED TRUCK	50%	2604	Chevrolet C3500	397	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.11	0.12	0.12	0.36	0.95	381.43	0.06
TRACTOR/40' FLOAT	10%	260.4	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.01	0.01	0.00	0.02	0.05	7.53	0.00
UTILITY CARTS (SITE TRANSP)	10%	520.8	John Deere HPX 4 x 4	21	Gas	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.00	0.00	0.00	0.02	0.03	4.25	0.00
B - EARTH MOVING																								
DREDGER	100%	434	Typical	1450	Diesel	1	1											2.0	0.14	0.16	0.16	1.29	6.72	361.08	0.67
580 BACKHOE	100%	434	Case 580N	78	Diesel	1	1											2.0	0.01	0.01	0.01	0.05	0.04	6.07	0.00
225 TRACK HOE	100%	868	Case CX210C	160	Diesel	2	2											4.0	0.02	0.01	0.01	0.06	0.10	15.15	0.00
EXTEND-A-HOE	100%	868	Case CX210C	161	Diesel	2	2											4.0	0.02	0.01	0.01	0.06	0.10	15.15	0.00
C - AIR OP EQUIP																								
185 COMPRESSOR	100%	4340	Sullair 185	61	Diesel			2	2	2	2	2	2	2	2	2	2	20.0	0.04	0.04	0.04	0.23	0.48	73.68	0.01
D - HEAVY EQUIP																								
300-T CRAWLER	100%	2170	Manitowac 2250	500	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	0.09	0.10	0.10	0.30	0.79	317.86	0.05
80-TON PICKER	100%	2170	Manitowac 2250	500	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	0.09	0.10	0.10	0.30	0.79	317.86	0.05
35-TON PICKER	100%	2170	Grove RT530E-2	164	Diesel			1	1	1	1	1	1	1	1	1	1	10.0	0.03	0.04	0.04	0.07	0.21	121.50	0.02
25-TON PICKER	100%	4340	Grove YB7725	130	Diesel			2	2	2	2	2	2	2	2	2	2	20.0	0.07	0.08	0.07	0.15	0.42	242.99	0.04
G - WELDING EQUIP																								
8-PAC WELDER'S	100%	4340	Electric Driven	N/A	Electric			2	2	2	2	2	2	2	2	2	2	20.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																								
GENERATOR'S 5KW	100%	8680	Honda EM5000S	11.7	Gas	4	4	4	4	4	4	4	4	4	4	4	4	40.0	0.44	0.01	0.01	27.51	0.17	97.64	0.02
																		Total	***1.21***	***0.85***	***0.83***	***30.93***	***12.04***	***2,523.40***	***1.04***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.13 Phase V Marine Work - Year 2017

Magnolia LNG Project

Construction Equipment Utilization Matrix

Marine Work

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year					Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																		
PICK-UP TRUCK or VAN newer then 2010	10%	217	GMC 1500	250	Gas	2	2	2	2	2	10.0	20.42	19.62	19.03	23.53	91.28	77,315.36	12.08
A - ROLLING EQUIP																		
2-T FLATBED TRUCK	50%	542.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	5.0	20.42	19.62	19.03	23.53	91.28	77,315.36	12.08
DUMP TRUCK 14CY	100%	0	Mack Truck Granite Series	415	Diesel	Not Used					0.0	36.34	38.53	37.38	92.23	262.71	132,884.93	21.86
FARM WAGON w/TRAILER	100%	1085	Kubota L4240	44	Diesel	1	1	1	1	1	5.0	3.15	3.37	3.27	15.69	39.25	6,747.42	1.26
FUEL TRUCK	30%	325.5	Chevrolet C3500	397	Diesel	1	1	1	1	1	5.0	36.34	38.53	37.38	92.23	262.71	132,884.93	21.86
MECH TRUCK	2%	21.7	GMC 1500	250	Gas	1	1	1	1	1	5.0	20.42	19.62	19.03	23.53	91.28	77,315.36	12.08
EXTEND-A-FORKLIFT	100%	2170	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	2	10.0	7.25	8.81	8.54	31.48	36.80	30,044.17	4.74
1-T STAKEBED TRUCK	50%	1085	Chevrolet C3500	397	Diesel	2	2	2	2	2	10.0	36.34	38.53	37.38	92.23	262.71	132,884.93	21.86
TRACTOR/40' FLOAT	10%	108.5	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	5.0	22.02	16.71	16.21	74.14	144.77	26,248.14	5.02
UTILITY CARTS (SITE TRANSP)	10%	217	John Deere HPX 4 x 4	21	Gas	2	2	2	2	2	10.0	5.89	4.52	4.38	29.88	55.49	7,403.72	1.59
B - EARTH MOVING																		
DREDGER	100%	0	Typical	1450	Diesel	Not Used					0.0	291.87	324.3	324.3	2702.5	14053	754765.01	1405.3
580 BACKHOE	100%	0	Case 580N	78	Diesel	Not Used					0.0	14.62	14.03	13.61	89.60	72.13	12,696.45	2.47
225 TRACK HOE	100%	0	Case CX210C	160	Diesel	Not Used					0.0	14.96	12.42	12.04	54.10	92.73	15,835.68	3.08
EXTEND-A-HOE	100%	0	Case CX210C	161	Diesel	Not Used					0.0	14.96	12.42	12.04	54.10	92.73	15,835.68	3.08
C - AIR OP EQUIP																		
185 COMPRESSOR	100%	2170	Sullair 185	61	Diesel	2	2	2	2	2	10.0	6.89	7.30	7.08	44.22	95.93	15,403.60	2.94
D - HEAVY EQUIP																		
300-T CRAWLER	100%	1085	Manitowac 2250	500	Diesel	1	1	1	1	1	5.0	36.34	38.53	37.38	92.23	262.71	132884.93	21.86
80-TON PICKER	100%	651	Manitowac 2250	500	Diesel	1	1	1			3.0	36.34	38.53	37.38	92.23	262.71	132884.93	21.86
35-TON PICKER	100%	1085	Grove RT530E-2	164	Diesel	1	1	1	1	1	5.0	13.62	14.33	13.90	22.60	63.89	50,793.94	8.04
25-TON PICKER	100%	1953	Grove YB7725	130	Diesel	2	2	2	2	1	9.0	13.62	14.33	13.90	22.60	63.89	50,793.94	8.04
G - WELDING EQUIP																		
8-PAC WELDER'S	100%	2170	Electric Driven	N/A	Electric	2	2	2	2	2	10.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																		
GENERATOR'S 5KW	100%	3472	Honda EM5000S	11.7	Gas	4	4	4	2	2	16.0	44.53	1.10	1.01	2,859.98	17.19	10,206.02	2.10

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.
Dredge will be vessel mounted. Assumed hp of vessel 1,450 hp, typical "Jekyll Island" vessel.
Note: Pile driver for installation of steel sheet pile bulkhead, five breasting dolphins using steel pilings and other plant pilings accounted for under Balance of Plant Phase.

2017 Annual Emission (ton)

DESCRIPTION	% Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year					Equipment Months	Annual Emission(ton)						
						1	2	3	4	5		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																		
PICK-UP TRUCK or VAN newer then 2010	10%	217	GMC 1500	250	Gas	2	2	2	2	2	10.0	0.00	0.00	0.00	0.01	0.02	18.49	0.00
A - ROLLING EQUIP																		
2-T FLATBED TRUCK	50%	542.5	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	5.0	0.01	0.01	0.01	0.01	0.05	46.23	0.01
DUMP TRUCK 14CY	100%	0	Mack Truck Granite Series	415	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FARM WAGON w/TRAILER	100%	1085	Kubota L4240	44	Diesel	1	1	1	1	1	5.0	0.00	0.00	0.00	0.02	0.05	8.07	0.00
FUEL TRUCK	30%	325.5	Chevrolet C3500	397	Diesel	1	1	1	1	1	5.0	0.01	0.01	0.01	0.03	0.09	47.68	0.01
MECH TRUCK	2%	21.7	GMC 1500	250	Gas	1	1	1	1	1	5.0	0.00	0.00	0.00	0.00	0.00	1.85	0.00
EXTEND-A-FORKLIFT	100%	2170	JLG 8042 Sky Trak Telehandler	100	Diesel	2	2	2	2	2	10.0	0.02	0.02	0.02	0.08	0.09	71.87	0.01
1-T STAKEBED TRUCK	50%	1085	Chevrolet C3500	397	Diesel	2	2	2	2	2	10.0	0.04	0.05	0.04	0.11	0.31	158.93	0.03
TRACTOR/40' FLOAT	10%	108.5	Mack Truck Pinnacle Series	505	Diesel	1	1	1	1	1	5.0	0.00	0.00	0.00	0.01	0.02	3.14	0.00
UTILITY CARTS (SITE TRANSP)	10%	217	John Deere HPX 4 x 4	21	Gas	2	2	2	2	2	10.0	0.00	0.00	0.00	0.01	0.01	1.77	0.00
B - EARTH MOVING																		
DREDGER	100%	0	Typical	1450	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
580 BACKHOE	100%	0	Case 580N	78	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
225 TRACK HOE	100%	0	Case CX210C	160	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EXTEND-A-HOE	100%	0	Case CX210C	161	Diesel	Not Used					0.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C - AIR OP EQUIP																		
185 COMPRESSOR	100%	2170	Sullair 185	61	Diesel	2	2	2	2	2	10.0	0.02	0.02	0.02	0.11	0.23	36.85	0.01
D - HEAVY EQUIP																		
300-T CRAWLER	100%	1085	Manitowac 2250	500	Diesel	1	1	1	1	1	5.0	0.04	0.05	0.04	0.11	0.31	158.93	0.03
80-TON PICKER	100%	651	Manitowac 2250	500	Diesel	1	1	1			3.0	0.03	0.03	0.03	0.07	0.19	95.36	0.02
35-TON PICKER	100%	1085	Grove RT530E-2	164	Diesel	1	1	1	1	1	5.0	0.02	0.02	0.02	0.03	0.08	60.75	0.01
25-TON PICKER	100%	1953	Grove YB7725	130	Diesel	2	2	2	2	1	9.0	0.03	0.03	0.03	0.05	0.14	109.35	0.02
G - WELDING EQUIP																		
8-PAC WELDER'S	100%	2170	Electric Driven	N/A	Electric	2	2	2	2	2	10.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I - ELECTRICAL EQUIP																		
GENERATOR'S 5KW	100%	3472	Honda EM5000S	11.7	Gas	4	4	4	2	2	16.0	0.17	0.00	0.00	10.95	0.07	39.06	0.01
											Total	***0.40***	***0.25***	***0.24***	***11.58***	***1.66***	***858.33***	***0.14***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

Table 9.A.14 Phase VI Miscellaneous - Year 2015

Magnolia LNG Project

Construction Equipment Utilization Matrix

SK E&C Management Team

DESCRIPTION	% Time Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year							Equipment Months	NONROAD Emission Factor (gram/hr)						
						6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																				
PICK-UP TRUCK or VAN newer then 2010	10%	716.1	GMC 1500	250	Gas	4	4	5	5	5	5	5	33.0	21.36	21.66	21.01	39.51	163.59	77,312	12.52
A - ROLLING EQUIP																				
WATER TRUCK	5%	75.95	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	7.0	31.47	30.51	29.60	118.91	362.12	73,925	14.12
FORKLIFT (WHSE Operations)	100%	3038	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	14.0	8.09	13.66	13.25	68.35	76.56	30,042	5.10
EXTEND-A-FORKLIFT (WHSE Operations)	100%	1519	JLG 8042 Sky Trak Telehandler	100	Diesel	1	1	1	1	1	1	1	7.0	8.09	13.66	13.25	68.35	76.56	30,042	5.10
UTILITY CARTS (SITE TRANSP)	10%	716.1	John Deere HPX 4 x 4	21	Gas	4	4	5	5	5	5	5	33.0	41.74	0.99	0.91	2,558.85	16.59	9,039	1.86

Note: values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % time and equipment months.

2015 Annual Emission (ton)

DESCRIPTION	% Time Used/Month	Project Hours in Operatoin	Model	HP Rating	Fuel Type	Month of Year							Equipment Months	Annual Emission (ton)						
						6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2e	SO2
SK TRUCKS & CARS																				
PICK-UP TRUCK or VAN newer then 2010	10%	716.1	GMC 1500	250	Gas	4	4	5	5	5	5	5	33.0	0.02	0.02	0.02	0.03	0.13	61.03	0.01
A - ROLLING EQUIP																				
WATER TRUCK	5%	75.95	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	7.0	0.00	0.00	0.00	0.01	0.03	6.19	0.00
FORKLIFT (WHSE Operations)	100%	3038	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	14.0	0.03	0.05	0.04	0.23	0.26	100.60	0.02
EXTEND-A-FORKLIFT (WHSE Operations)	100%	1519	JLG 8042 Sky Trak Telehandler	100	Diesel	1	1	1	1	1	1	1	7.0	0.01	0.02	0.02	0.11	0.13	50.30	0.01
UTILITY CARTS (SITE TRANSP)	10%	716.1	John Deere HPX 4 x 4	21	Gas	4	4	5	5	5	5	5	33.0	0.03	0.00	0.00	2.02	0.01	7.14	0.00
													Total	***0.09***	***0.09***	***0.09***	***2.40***	***0.56***	***225.26***	***0.04***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

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Table 9.A.15 Phase VI Miscellaneous - Year 2016

Magnolia LNG Project

Construction Equipment Utilization Matrix

SK E&C Management Team

DESCRIPTION	% Time Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	1692.6	GMC 1500	250	Gas	5	5	5	5	6	7	7	7	7	8	8	8	78.0	20.75	20.35	19.74	29.24	123.79	77,314	12.23
A - ROLLING EQUIP																									
WATER TRUCK	5%	130.2	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	29.44	28.94	28.07	106.06	318.14	73,931	13.81
FORKLIFT (WHSE Operations)	100%	5208	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	7.48	10.14	9.83	41.50	52.52	30,043	4.84
EXTEND-A-FORKLIFT (WHSE Operations)	100%	2604	JLG 8042 Sky Trak Telehandler	100	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	7.48	10.14	9.83	41.50	52.52	30,043	4.84
UTILITY CARTS (SITE TRANSP)	10%	1692.6	John Deere HPX 4 x 4	21	Gas	5	5	5	5	6	7	7	7	7	8	8	8	78.0	5.91	4.53	4.39	30.24	55.48	7,404	1.59

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2016 Annual Emission (ton)

DESCRIPTION	% Time Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	1692.6	GMC 1500	250	Gas	5	5	5	5	6	7	7	7	7	8	8	8	78.0	0.04	0.04	0.04	0.05	0.23	144.25	0.02
A - ROLLING EQUIP																									
WATER TRUCK	5%	130.2	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.02	0.05	10.61	0.00
FORKLIFT (WHSE Operations)	100%	5208	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.04	0.06	0.06	0.24	0.30	172.47	0.03
EXTEND-A-FORKLIFT (WHSE Operations)	100%	2604	JLG 8042 Sky Trak Telehandler	100	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.02	0.03	0.03	0.12	0.15	86.24	0.01
UTILITY CARTS (SITE TRANSP)	10%	1692.6	John Deere HPX 4 x 4	21	Gas	5	5	5	5	6	7	7	7	7	8	8	8	78.0	0.01	0.01	0.01	0.06	0.10	13.81	0.00
																		Total	***0.12***	***0.14***	***0.13***	***0.48***	***0.83***	***427.39***	***0.07***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

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Table 9.A.16 Phase VI Miscellaneous - Year 2017

Magnolia LNG Project

Construction Equipment Utilization Matrix

SK E&C Management Team

DESCRIPTION	% Time Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	NONROAD Emission Factor (gram/hr)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	1974.7	GMC 1500	250	Gas	8	8	8	8	8	8	8	8	8	7	6	6	91.0	13.62	14.33	13.90	22.60	63.89	50,793.94	8.04
A - ROLLING EQUIP																									
WATER TRUCK	5%	130.2	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	27.56	27.66	26.83	93.98	279.40	73,936.37	13.50
FORKLIFT (WHSE Operations)	100%	5208	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	7.25	8.81	8.54	31.48	36.80	30,044.17	4.74
EXTEND-A-FORKLIFT (WHSE Operations)	100%	2604	JLG 8042 Sky Trak Telehandler	100	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	7.25	8.81	8.54	31.48	36.80	30,044.17	4.74
UTILITY CARTS (SITE TRANSP)	10%	1974.7	John Deere HPX 4 x 4	21	Gas	8	8	8	8	8	8	8	8	8	7	6	6	91.0	5.89	4.52	4.38	29.88	55.49	7,403.72	1.59

Note: Values under Project Month indicate number of each type of equipment used during indicated month. Equipment month is sum of number of equipment per month for year.
Project hours in operation based on 217 work hours per month, multiplied by % used and equipment months.

2017 Annual Emission (ton)

DESCRIPTION	% Time Used/Month	Project Hours in Operation	Model	HP Rating	Fuel Type	Month of Year												Equipment Months	Annual Emission (ton)						
						1	2	3	4	5	6	7	8	9	10	11	12		VOC	PM10	PM2.5	CO	NOx	CO2	SO2
SK TRUCKS & CARS																									
PICK-UP TRUCK or VAN newer then 2010	10%	1974.7	GMC 1500	250	Gas	8	8	8	8	8	8	8	8	8	7	6	6	91.0	0.03	0.03	0.03	0.05	0.14	110.56	0.02
A - ROLLING EQUIP																									
WATER TRUCK	5%	130.2	Chevrolet Kodiak C5500	300	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.00	0.00	0.00	0.01	0.04	10.61	0.00
FORKLIFT (WHSE Operations)	100%	5208	Cat PD10000	77	Diesel	2	2	2	2	2	2	2	2	2	2	2	2	24.0	0.04	0.05	0.05	0.18	0.21	172.48	0.03
EXTEND-A-FORKLIFT (WHSE Operations)	100%	2604	JLG 8042 Sky Trak Telehandler	100	Diesel	1	1	1	1	1	1	1	1	1	1	1	1	12.0	0.02	0.03	0.02	0.09	0.11	86.24	0.01
UTILITY CARTS (SITE TRANSP)	10%	1974.7	John Deere HPX 4 x 4	21	Gas	8	8	8	8	8	8	8	8	8	7	6	6	91.0	0.01	0.01	0.01	0.07	0.12	16.12	0.00
Total																			***0.11***	***0.12***	***0.12***	***0.40***	***0.62***	***396.01***	***0.06***

Note

1. Assume 50 hours per week and 4.33 weeks per month. The total operation hour is 217 for a month.

2. 1 ton=907185 gram

3. Annual Emission = Hourly Emission (emission factor) * Project Hours in operation/907185.

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Table 9.A.17 - Construction Material Transport by Tug/Barge in Year 2016

			Emissions (tons in 2016)											Engine
Marine Operations		kilowatts (each)	**VOC**	**PM10**	**PM2.5**	**CO**	**NOx**	**CO2e**	**CO2**	**N2O**	**CH4**	**SO2**	**PM**	**Load Factor**
	Tugs (3100 hp) - barge push	2312	0.52	0.58	0.58	4.82	25.06	1345.71	1330.12	0.04	0.17	2.51	0.58	0.85
	Tugs (3100 hp) - idle mode	578	0.02	0.02	0.02	0.14	0.74	39.58	39.12	0.00	0.01	0.07	0.02	0.25
Subtotal Vessels			**0.54**	**0.60**	**0.60**	**4.96**	**25.80**	**1385.29**	**1369.24**	**0.04**	**0.18**	**2.58**	**0.60**	

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Table 9.A.18 - Tug/Barge Construction Material Transport Activity List

CONSTRUCTION PHASE	Activity	Number of Round Trips	Pieces of Equipment	Horsepower	Fuel Type	Distance Each Trip	Average Speed (mph)	Hours of Operation	Total Idle Hours (estimate)	
Pile Delivery	Transport concrete LNG tank storage piles from point 7 miles away, RT = 14 miles	5	1	3100	Diesel	14	2	35	3.5	
	Transport liquefaction modules from point up to 50 miles away, RT = 100 miles	16	1	3100	Diesel	100	2	250	25	
	Transport rock seawall armoring from point up to 50 miles away, RT = 100 miles	12	1	3100	Diesel	100	2	250	25	
	Transport sheet pile from point 50 miles away, RT = 100 miles	4	1	3100	Diesel	100	2	250	25	
	Transport marine pilings and mooring assemblies from point 7 miles away, RT = 14 miles	4	1	3100	Diesel	14	2	35	3.5	
	Transport concrete balance of plant storage piles from point 7 miles away, RT = 14 miles	5	1	3100	Diesel	14	2	35	3.5	
	Provision for Miscellaneous Deliveries	4	1	3100	Diesel	14	2	35	3.5	
	Total	50						890	89	

Rev: 10/30/2013

Assumptions:
Average trip speed 2 mph @ 85% engine load
All trips occur in year 2016
Tug present while barges being loaded/unloaded used intermittently to position barges for loading /unloading
One tug assigned to project
Idle time is assumed 10% of hours of operation

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Table 9.A.19 - Tug and Dredge Vessel Emission Factors

		Emission Factors (g/kw-hr)										engine emiss tier	engine power cat
	Kilowatts (each)	**VOC**	**PM10**	**PM2.5**	**CO**	**NOx**	**CO2**	**N2O**	**CH4**	**SO2**	**PM**		
Tugs (3100 hp) - barge push	2312	0.27	0.3	0.3	2.5	13	690	0.02	0.09	1.3	0.3	0	1
Tugs (3100 hp) - idle mode (25% of full kw)	578	0.27	0.3	0.3	2.5	13	690	0.02	0.09	1.3	0.3	0	1
Dredger - Medium (1450 hp)	1081	0.27	0.3	0.3	2.5	13	690	0.02	0.09	1.3	0.3	0	1

Data Source: ICF Best Practices for Port Emission Inventories, Table 3-8 Harbor Craft Emission Factors
Notes: according to ICF Best practices, most tugs are Cat 1 (75% to 90%) with remainder Cat 2 (however, it is very port/harbor specific).



Jekyll Island
1,450 HP; 1,081 kW; assume Tier 0
14" Cutter Suction Head Dredge

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Table 9.A.20 - Fugitive Dust Emissions from General Site Work and Earth Moving

	General Construction Site Work				Earth Moving			Summary		
Site	From RR1 Acres disturbed	Estimated Duration (months)	PM10 Emiss Factor ton/acre/month	PM 10 emiss tons	cu yds	EF ton/1000 cu yd	PM10 (tons)	**Total PM10 (tons)**	PM2.5/PM10 ratio	**Total PM2.5 (tons)**
Magnolia 2015	108	6	0.011	7.1	131200	0.059	7.7	**14.9**	0.1	**1.5**
Magnolia 2016	108	12	0.011	14.3	0	0.059	0.0	**14.3**	0.1	**1.4**
Magnolia 2017	108	12	0.011	14.3	0	0.059	0.0	**14.3**	0.1	**1.4**

Note: General construction site work and earth moving emission factors used are from Table 3-2, Level 2 basis from Western Regional Air Partnership Fugitive Dust Handbook (WRAP FDH) (revised 2006). PM2.5 to PM10 ratio based on WRAP FDH as well.

131200 cubic yards soil excavated from upland areas and placed on site.

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Table 9.A.21 - Fugitive Dust Emissions from Unpaved Roads

Site				Emissions (tons)								
	VMT	% Paved	% Unpaved	TSP Paved	TSP Unpaved	PM10 Paved	PM10 Unpaved	PM2.5 Paved	PM2.5 Unpaved	TSP Total	PM10 Total	PM2.5 Total
Heavy Haul Road	60	0	100	0.00	0.33	0.00	0.09	0.00	0.01	0.33	0.09	0.01
Note: VMT estimated based on use of 100 round trips of 0.6 miles each RT with SPMTs. Heavy haul road is 1,500 foot road from Dynamic Industries Yard.												

Paved Road EF Input Parameter	Value	Parameter Value Data source
Particle Size multiplier PM10	0.0022	From AP-42, Table 13.2.1-1
Particle Size multiplier PM2.5	0.00054	From AP-42, Table 13.2.1-1
Particle Size multiplier TSP	0.011	From AP-42, Table 13.2.1-1
Road surface silt (g/m2)	0.2	From WRAP Table 5-2, baseline silt loading for public paved road with ADT 500 to 5,000
W average vehicle wt (tons)	2.5	Based on estimate of typical weight of cars and SUVs
Calculated PM10 EF (lb/VMT)	**0.001295**	Equation from AP-42 section 13.2.1 Paved Roads
Calculated PM2.5 EF (lb/VMT)	**0.000318**	Equation from AP-42 section 13.2.1 Paved Roads
Calculated TSP EF (lb/VMT)	**0.006475**	Equation from AP-42 section 13.2.1 Paved Roads

UnPaved Road EF Input Parameter	Value	Parameter Value Data source
Particle Size multiplier PM10	1.5	From AP-42, Table 13.2.2-2
Particle Size multiplier PM2.5	0.15	From AP-42, Table 13.2.2-2
Particle Size multiplier TSP	4.9	From AP-42, Table 13.2.2-2
Road surface silt (%)	8.5	From AP-42, Table 13.2.2-1, Construction Sites scraper routes mean value
W average vehicle wt (tons)	30	Based on estimate of weight of SPMT
Constant "a" for equation PM10	0.9	From AP-42, Table 13.2.2-2
Constant "a" for equation PM2.5	0.9	From AP-42, Table 13.2.2-2
Constant "a" for equation TSP	0.7	From AP-42, Table 13.2.2-2
Constant "b" for equation PM10	0.45	From AP-42, Table 13.2.2-2
Constant "b" for equation PM2.5	0.45	From AP-42, Table 13.2.2-2
Constant "b" for equation TSP	0.45	From AP-42, Table 13.2.2-2
Calculated PM10 EF (lb/VMT)	**3.099597**	Equation from AP-42 section 13.2.2 Unpaved Roads
Calculated PM2.5 EF (lb/VMT)	**0.30996**	Equation from AP-42 section 13.2.2 Unpaved Roads
Calculated TSP EF (lb/VMT)	**10.84832**	Equation from AP-42 section 13.2.2 Unpaved Roads

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Table 9.A.22 - On-Road Worker Commute Emissions

	From MOVES for Calcasieu Parish		Emission Factor Calculated	2015			2016			2017		
Pollutant	emiss (g)	Distance (mi)	grams/mi	miles/yr	gm/yr	tons/yr	miles/yr	gm/yr	tons/yr	miles/yr	gm/yr	tons/yr
CO	99624395.59	84673680.67	1.17656862	1259356	1481719	1.6334	2158896	2540089	2.8000	2158896	2540089	2.8000
NOx	7550948.599	84673680.67	0.089177045	1259356	112306	0.1238	2158896	192524	0.2122	2158896	192524	0.2122
SO2	329748.1978	84673680.67	0.003894341	1259356	4904	0.0054	2158896	8407	0.0093	2158896	8407	0.0093
VOC	1297832.909	84673680.67	0.015327465	1259356	19303	0.0213	2158896	33090	0.0365	2158896	33090	0.0365
CO2e	14531201485	84673680.67	171.614147	1259356	216123306	238.2403	2158896	370497096	408.4120	2158896	370497096	408.4120
PM10exh	212805.0997	84673680.67	0.002513238	1259356	3165	0.0035	2158896	5426	0.0060	2158896	5426	0.0060
PM10brake	518493.8521	84673680.67	0.006123436	1259356	7712	0.0085	2158896	13220	0.0146	2158896	13220	0.0146
PM10tire	241995.4865	84673680.67	0.002857978	1259356	3599	0.0040	2158896	6170	0.0068	2158896	6170	0.0068
PM25exh	195953.1481	84673680.67	0.002314216	1259356	2914	0.0032	2158896	4996	0.0055	2158896	4996	0.0055
PM25brake	135731.3843	84673680.67	0.001602994	1259356	2019	0.0022	2158896	3461	0.0038	2158896	3461	0.0038
PM25tire	58032.49005	84673680.67	0.000685366	1259356	863	0.0010	2158896	1480	0.0016	2158896	1480	0.0016
Total PM10	(sum of PM10 exh, PM10 brake, PM10 tire)				14476	0.0160		24816	0.0274		24816	0.0274
Total PM2.5	(sum of PM2.5 exh, PM2.5 brake, PM2.5 tire)				5796	0.0064		9936	0.0110		9936	0.0110

Note: car commuting mileage for construction workers provided by S&K construction engineering estimate

179908 miles per month for 31 months

7 months in 2015

12 months in 2016

12 months in 2017

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Appendix 9.B
Operational Emissions

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Appendix 9.B.1

Operational Emissions Calculations

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Table No	Table Name
Table 1	Facility-Wide Emissions
Table 2	Emissions for Each LNG Train
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Table 17	Process Streams and Piping Component Counts
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Table 19	LNG Vessel and Tug Boat Operational Emissions
Table 20	Operational Mobile Sources - Magnolia LNG

NOTE: Tables 17 and 18 are PRIVILEGED and are provided separately in Appendix 9.B.2.

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Table 1
Facility-Wide Emissions
Magnolia LNG

		Annual Emissions (tpy)																
		Stationary Sources													Mobile Sources			
Pollutant Type	Pollutant	LNG Train 1	LNG Train 2	LNG Train 3	LNG Train 4	Warm Gas Flare	Cold Gas Flare	Emergency Generator	Emergency Fire Pump 1	Emergency Fire Pump 2	Deluge Pump 1	Deluge Pump 2	Fugitive Emissions	SUBTOTAL	LNG Vessels and Tug Boats	Operational Mobile Sources	SUBTOTAL	TOTAL
Criteria	NO_x	282.94	282.94	282.94	282.94	8.31	4.51	3.55	0.59	0.59	2.12	2.12		**1,153.55**	328.68	66.09	**394.77**	**1,548.32**
	CO	182.27	182.27	182.27	182.27	45.19	24.54	1.92	0.51	0.51	1.15	1.15		**804.04**	42.10	6.26	**48.37**	**852.41**
	VOC	13.15	13.15	13.15	13.15	0.72	0.01	0.35	0.06	0.06	0.21	0.21	14.69	**68.91**	18.94	2.51	**21.45**	**90.37**
	PM	21.50	21.50	21.50	21.50	1.01	0.55	0.11	0.03	0.03	0.07	0.07		**87.88**	14.66	3.61	**18.27**	**106.15**
	PM_{10}	21.50	21.50	21.50	21.50	1.01	0.55	0.09	0.02	0.02	0.05	0.05		**87.82**	14.66	3.61	**18.27**	**106.10**
	$PM_{2.5}$	21.50	21.50	21.50	21.50	1.01	0.55	0.08	0.02	0.02	0.05	0.05		**87.78**	14.66	3.61	**18.27**	**106.05**
	SO_2	33.45	33.45	33.45	33.45			0.004	0.001	0.001	0.002	0.002		**133.80**	2.63	0.03	**2.66**	**136.46**
HAPs	Acetaldehyde	0.11	0.11	0.11	0.11									**0.45**				**0.45**
	Acrolein	0.02	0.02	0.02	0.02									**0.07**				**0.07**
	Benzene	0.07	0.07	0.07	0.07	0.0042	0.00005	0.002	0.0006	0.0006	0.001	0.001	0.02	**0.32**				**0.32**
	Ethylbenzene	0.09	0.09	0.09	0.09									**0.36**				**0.36**
	Formaldehyde	2.02	2.02	2.02	2.02	0.01	0.01		0.0007	0.0007				**8.10**				**8.10**
	Hexane	0.32	0.32	0.32	0.32	0.046	0.0006						0.24	**1.57**				**1.57**
	Napthalene	0.004	0.004	0.004	0.004									**0.01**				**0.01**
	PAH	0.006	0.006	0.006	0.006									**0.02**				**0.02**
	Toluene	0.38	0.38	0.38	0.38	0.0016	0.0000	0.0007					0.01	**1.54**				**1.54**
	Xylenes	0.20	0.20	0.20	0.20	0.0019	0.0000						0.01	**0.80**				**0.80**
	Total HAPs	**3.22**	**3.22**	**3.22**	**3.22**	**0.064**	**0.006**	**0.002**	**0.001**	**0.001**	**0.001**	**0.001**	**0.28**	**13.25**				**13.25**
Non-HAP TACs	Ammonia	1.45	1.45	1.45	1.45								1.54	**7.33**				**7.33**
	H_2S	0.96	0.96	0.96	0.96									**3.83**				**3.83**
Greenhouse Gas	CO_2	516,534.36	516,534.36	516,534.36	516,534.36	15,878.92	8,623.47	384.05	98.75	98.75	201.21	201.21	1.93	**2,091,625.72**	21,231.95	3,451.55	**24,683.50**	**2,116,309.23**
	N_2O	10.38	10.38	10.38	10.38	0.03	0.01	0.003	0.001	0.001	0.002	0.002		**41.57**	0.41	0.10	**0.51**	**42.08**
	CH_4	72.33	72.33	72.33	72.33	26.89	13.87	0.02	0.005	0.005	0.010	0.010	88.79	**418.91**	1.65	0.45	**2.10**	**421.02**

		Annual Emissions (ton CO_2e/yr)																
		Stationary Sources													Mobile Sources			
	Pollutant	LNG Train 1	LNG Train 2	LNG Train 3	LNG Train 4	Process Flare	Marine Flare	Emergency Generator	Emergency Fire Pump 1	Emergency Fire Pump 2	Deluge Pump 1	Deluge Pump 2	Fugitive Emissions	SUBTOTAL	LNG Vessels and Tug Boats	Operational Mobile Sources	SUBTOTAL	TOTAL
Greenhouse Gas (CO_2e)	CO_2	516,534.36	516,534.36	516,534.36	516,534.36	15,878.92	8,623.47	384.05	98.75	98.75	201.21	201.21	1.93	**2,091,625.72**	21,231.95	3,451.55	**24,683.50**	**2,116,309.23**
	N_2O	3,093.05	3,093.05	3,093.05	3,093.05	8.01	4.35	0.92	0.24	0.24	0.48	0.48		**12,386.93**	122.25	29.81	**152.06**	**12,538.99**
	CH_4	1,808.17	1,808.17	1,808.17	1,808.17	672.34	346.80	0.47	0.12	0.12	0.25	0.25	2,219.74	**10,472.79**	41.33	11.26	**52.59**	**10,525.38**
	Total GHGs	**521,435.58**	**521,435.58**	**521,435.58**	**521,435.58**	**16,559.28**	**8,974.62**	**385.43**	**99.11**	**99.11**	**201.94**	**201.94**	**2,221.67**	**2,114,485.44**	**21,395.53**	**3,492.62**	**24,888.15**	**2,139,373.59**

Table 2
Emissions for Each LNG Train
Magnolia LNG

Pollutant Type	Pollutant	Annual Emissions (tpy)					
		Turbine A	Turbine B	Thermal Oxidizer	Auxiliary Boiler	Ammonia Vent	TOTAL
Criteria	NO_x	127.41	127.41	7.87	20.24		**282.94**
	CO	77.57	77.57	6.59	20.54		**182.27**
	VOC	5.25	5.25	0.77	1.88		**13.15**
	PM	9.28	9.28	1.06	1.88		**21.50**
	PM_{10}	9.28	9.28	1.06	1.88		**21.50**
	$PM_{2.5}$	9.28	9.28	1.06	1.88		**21.50**
	SO_2	0.13	0.13	33.10	0.09		**33.45**
HAPs	Acetaldehyde	0.06	0.06				**0.11**
	Acrolein	0.01	0.01				**0.02**
	Benzene	0.02	0.02	0.005	0.03		**0.07**
	Ethylbenzene	0.04	0.04		0.0005		**0.09**
	Formaldehyde	1.00	1.00	0.01	0.02		**2.02**
	Hexane			0.01	0.31		**0.32**
	Napthalene	0.002	0.002				**0.004**
	PAH	0.003	0.003				**0.006**
	Toluene	0.18	0.18	0.002	0.01		**0.38**
	Xylenes	0.09	0.09	0.002	0.02		**0.20**
	Total HAPs	**1.40**	**1.40**	**0.02**	**0.40**		**3.22**
Non-HAP TACs	Ammonia					1.45	**1.45**
	H_2S			0.96			**0.96**
Greenhouse Gas	CO_2	164,592.34	164,592.34	136,848.28	50,501.40		**516,534.36**
	N_2O	4.22	4.22	0.05	1.90		**10.38**
	CH_4	20.99	20.99	29.24	1.11		**72.33**

	Pollutant	Annual Emissions (ton CO_2e/yr)					
		Turbine A	Turbine B	Thermal Oxidizer	Auxiliary Boiler		TOTAL
Greenhouse Gas (CO_2e)	CO_2	164,592.34	164,592.34	136,848.28	50,501.40		**516,534.36**
	N_2O	1,257.10	1,257.10	13.78	565.07		**3,093.05**
	CH_4	524.72	524.72	730.90	27.82		**1,808.17**
	Total GHGs	**166,374.16**	**166,374.16**	**137,592.96**	**51,094.29**		**521,435.58**

Table 3
Emissions for Gas Turbine
Magnolia LNG

Parameter	Units	Average Value	Maximum Value
Fuel Lower Heating Value (LHV)[1]	Btu/scf	935.1	935.1
Fuel Higher Heating Value (HHV) [1]	Btu/scf	1036.4	1036.4
Ratio of HHV to LHV	-	1.108	1.108
Hourly Fuel Flow (LHV)[2]	MMBtu/hr	289.66	312.63
Hourly Fuel Flow (HHV)[3]	MMBtu/hr	321.04	346.50
Annual Operation	hr/yr	8760	-

Pollutant Type	Pollutant	HHV Emission Factor[4] (lb/MMBtu)	Average Hourly Emission Rate[5,6] (lb/hr)	Maximum Hourly Emission Rate[5,6] (lb/hr)	Annual Emissions (tpy)
Criteria	NO_x	-	29.09	31.42	127.41
	CO	-	17.71	19.13	77.57
	VOC	-	1.20	1.29	5.25
	PM	0.0066	2.12	2.29	9.28
	PM_{10}	0.0066	2.12	2.29	9.28
	$PM_{2.5}$	0.0066	2.12	2.29	9.28
	SO_2	0.000094	0.03	0.03	0.13
HAPs	Acetaldehyde	0.000040	0.01	0.01	0.06
	Acrolein	0.0000064	0.002	0.002	0.01
	Benzene	0.000012	0.004	0.004	0.02
	Ethylbenzene	0.000032	0.01	0.01	0.04
	Formaldehyde	0.00071	0.23	0.25	1.00
	Napthalene	0.0000013	0.0004	0.0005	0.002
	PAH	0.0000022	0.0007	0.0008	0.003
	Toluene	0.00013	0.04	0.05	0.18
	Xylene	0.000064	0.02	0.02	0.09
	Total HAPs	**-**	**0.32**	**0.35**	**1.40**
Greenhouse Gas	CO_2	-	37,578.16	40,596.22	164,592.34
	N_2O	0.003	0.96	1.04	4.22
	CH_4	-	4.79	5.12	20.99

Pollutant Type	Pollutant	Global Warming Potential (GWP)	Average Hourly Emission Rate (lb CO_2e/hr)	Maximum Hourly Emission Rate (lb CO_2e/hr)	Annual Emissions (ton CO_2e/yr)
Greenhouse Gas (CO_2e)	CO_2	1	37,578	40,596	164,592
	N_2O	298	287	310	1,257
	CH_4	25	120	128	525
	Total GHGs	**-**	**37,985**	**41,034**	**166,374**

Notes:

1. Based on manaufacturer's data.

2. Based on manaufacturer's data.

3. Calculated based on ratio of HHV to LHV.

4. Emissions factors from USEPA AP-42 Fifth Edition, Volume I - Section 3.1 - Stationary Gas Turbines. PM emission factors based on total PM (condensible and filterable fraction). PM_{10} and $PM_{2.5}$ emission factors assumed equal to total PM emission factor (condensible and filterable fractions). SO_2 emission factor based on sulfur content of <0.0001% by weight (equivalent to <0.00005% molar).

5. NO_x, CO, VOC, CO_2, and CH_4 emissions based on manufacturer's data.

6. PM, PM_{10}, and $PM_{2.5}$, N_2O, and individual HAP emissions based on AP-42 emission factors and maximum fuel flow rate.

Table 4
Emissions for Thermal Oxidizer - Design/Maximum Conditions
Magnolia LNG

Parameter	Amine Plant Exhaust	Combustion Gas	TOTAL
Feed Rate[1,2] (kg/hr)	14,030	443	**14,473**
Feed Rate (lb/hr)	30,931	977	**31,907**
LHV[3] (kcal/kg)	0	11,520	**11,520**
Heat Rate (kcal/hr)	0	5,103,360	**5,103,360**
Heat Rate (MMBtu/hr)	0	20.25	**20.25**
HC Desctruction Efficiency[3]	-	-	**99%**
Hours of Operation (hr/yr)	-	-	**8,760**

Component	Component MW (lb/lbmole)	Molar (Volume) Fraction[1] (mol %)		Weight Fraction (wgt %)		Feed Rate (lb/hr)		
		CO_2	Feed Gas	CO_2	Feed Gas	CO_2	Feed Gas	TOTAL
CO_2	44.01	99.9760%	0.0005%	99.9814%	0.0013%	30925.07	0.01	30925.08
Nitrogen	28.01	0.0000%	1.0136%	0.0000%	1.6883%	0.00	16.49	16.49
Methane	16.04	0.0000%	95.5445%	0.0000%	91.1401%	0.00	890.12	890.12
Ethane	30.07	0.0000%	2.5581%	0.0000%	4.5737%	0.00	44.67	44.67
Propane	44.10	0.0000%	0.3243%	0.0000%	0.8503%	0.00	8.30	8.30
i-Butane	58.12	0.0000%	0.0912%	0.0000%	0.3152%	0.00	3.08	3.08
n-Butane	58.12	0.0000%	0.0912%	0.0000%	0.3152%	0.00	3.08	3.08
i-Pentane	72.15	0.0000%	0.0811%	0.0000%	0.3479%	0.00	3.40	3.40
n-Pentane	72.15	0.0000%	0.0811%	0.0000%	0.3479%	0.00	3.40	3.40
n-Hexane	86.18	0.0000%	0.0304%	0.0000%	0.1558%	0.00	1.52	1.52
Benzene	78.11	0.0000%	0.0031%	0.0000%	0.0144%	0.00	0.14	0.14
Cyclohexane	84.16	0.0000%	0.0010%	0.0000%	0.0050%	0.00	0.05	0.05
n-Heptane	100.21	0.0000%	0.0051%	0.0000%	0.0304%	0.00	0.30	0.30
Toluene	92.14	0.0000%	0.0010%	0.0000%	0.0055%	0.00	0.05	0.05
n-Octane	114.23	0.0000%	0.0031%	0.0000%	0.0211%	0.00	0.21	0.21
p-Xylene	106.17	0.0000%	0.0010%	0.0000%	0.0063%	0.00	0.06	0.06
Ethylbenzene	106.17	0.0000%	0.0000%	0.0000%	0.0000%	0.00	0.00	0.00
H_2S	34.08	0.0240%	0.0000%	0.0186%	0.0000%	5.75	0.00	5.75
H_2O	18.02	0.0000%	0.1696%	0.0000%	0.1817%	0.00	1.77	1.77
Total	**-**	**100%**	**100%**	**100%**	**100%**	**30,931**	**977**	**31,907**

Actual Stack Temperature[4]	1500 F	816 C	1089 K
Actual Stack Pressure	1 atm	101325 Pa	
Normlized Temperature	32 F	0 C	273 K
Normalized Pressure	1 atm	101325 Pa	
Ideal Gas Constant	8.314 m^3-Pa/mol-K		

Flow Constituent	Flue gas flow[4] (lb-mole/hr)	Flue gas flow (mole/hr)	Mole Fraction (%)	Normalized Flow (Nm^3/hr)	Actual Flow	
					(m^3/hr)	(acfm)
CO_2	719.89	326,535	49.8%	7,315	29,166	17,164
H_2O	142.31	64,550	9.9%	1,446	5,766	3,393
N_2	553.22	250,935	38.3%	5,621	22,413	13,190
O_2	29.32	13,299	2.0%	298	1,188	699
TOTAL	**1,444.74**	**655,320**	**100.0%**	**14,679**	**58,533**	**34,446**

Pollutant Type	Pollutant	Emission Factor[5,6,7]			Maximum Hourly Emission Rate[8,9]
		ppmvd @3% O_2	mg/Nm^3	lb/MMBtu	(lb/hr)
Criteria	NO_x	40	74	-	2.40
	CO	-	62	-	2.01
	VOC	-	-	-	0.24
	PM	-	10	-	0.32
	PM_{10}	-	10	-	0.32
	$PM_{2.5}$	-	10	-	0.32
	SO_2	-	-	-	10.08
HAPs	Benzene	-	-	-	0.0014
	Formaldehyde	-	-	0.000081	0.0016
	n-Hexane	-	-	-	0.0021
	Toluene	-	-	-	0.00054
	Xylene	-	-	-	0.00062
	Total HAPs		**-**	**-**	**0.0063**
Non-HAP TACs	H_2S	5	6.9	-	0.22
Greenhouse Gas	CO_2	-	-	-	31,682.36
	N_2O	-	-	0.00070	0.01
	CH_4	-	-	-	8.90

Pollutant Type	Pollutant	Global Warming Potential (GWP)	Maximum Hourly Emission Rate (lb/hr)
Greenhouse	CO_2	1	31,682.36
Gas	N_2O	298	4.20
(CO_2e)	CH_4	25	222.53
	Total GHGs	**-**	**31,909.08**

Notes:
1. Combined flow to oxidizer.
2. Engineering estimates
3. Engineering estimates
4. Engineering estimates
5. NOx emission factor (in ppmvd @ 3%O2) based on engineering estimates.
6. CO and PM emission factors and H_2S emission factor (in ppmvd @ 3%O2) based on enginnering estimates.
7. Formaldehyde and N_2O emissions factors from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
8. Emission rates for VOC, CH_4, and individual HAPs (except formaldehyde) calculated from total feed rate and rated HC destruction efficiency.
9. SO_2 emission rate based on conversion of H_2S in total feed rate except for the H_2S assumed to be released to the stack (i.e., 5 ppmvd @ 3%O_2).

Table 5
Emissions for Thermal Oxidizer - Average Conditions
Magnolia LNG

Parameter	Amine Plant Exhaust	Combustion Gas	TOTAL
Feed Rate[1,2] (kg/hr)	10,521	332	**10,853**
Feed Rate (lb/hr)	23,195	732	**23,927**
LHV[3] (kcal/kg)	0	11,520	**11,520**
Heat Rate (kcal/hr)	0	3,826,974	**3,826,974**
Heat Rate (MMBtu/hr)	0	15.19	**15.19**
HC Desctruction Efficiency[4]	-	-	**99%**
Hours of Operation (hr/yr)	-	-	**8,760**

Component	Component MW (lb/lbmole)	Molar (Volume) Fraction[1] (mol %)		Weight Fraction (wgt %)		Feed Rate (lb/hr)		
		CO_2	Feed Gas	CO_2	Feed Gas	CO_2	Feed Gas	TOTAL
CO_2	44.01	99.9760%	0.0005%	99.9814%	0.0013%	23190.50	0.01	23190.51
Nitrogen	28.01	0.0000%	1.0136%	0.0000%	1.6883%	0.00	12.36	12.36
Methane	16.04	0.0000%	95.5445%	0.0000%	91.1401%	0.00	667.49	667.49
Ethane	30.07	0.0000%	2.5581%	0.0000%	4.5737%	0.00	33.50	33.50
Propane	44.10	0.0000%	0.3243%	0.0000%	0.8503%	0.00	6.23	6.23
i-Butane	58.12	0.0000%	0.0912%	0.0000%	0.3152%	0.00	2.31	2.31
n-Butane	58.12	0.0000%	0.0912%	0.0000%	0.3152%	0.00	2.31	2.31
i-Pentane	72.15	0.0000%	0.0811%	0.0000%	0.3479%	0.00	2.55	2.55
n-Pentane	72.15	0.0000%	0.0811%	0.0000%	0.3479%	0.00	2.55	2.55
n-Hexane	86.18	0.0000%	0.0304%	0.0000%	0.1558%	0.00	1.14	1.14
Benzene	78.11	0.0000%	0.0031%	0.0000%	0.0144%	0.00	0.11	0.11
Cyclohexane	84.16	0.0000%	0.0010%	0.0000%	0.0050%	0.00	0.04	0.04
n-Heptane	100.21	0.0000%	0.0051%	0.0000%	0.0304%	0.00	0.22	0.22
Toluene	92.14	0.0000%	0.0010%	0.0000%	0.0055%	0.00	0.04	0.04
n-Octane	114.23	0.0000%	0.0031%	0.0000%	0.0211%	0.00	0.15	0.15
p-Xylene	106.17	0.0000%	0.0010%	0.0000%	0.0063%	0.00	0.05	0.05
Ethylbenzene	106.17	0.0000%	0.0000%	0.0000%	0.0000%	0.00	0.00	0.00
H_2S	34.08	0.0240%	0.0000%	0.0186%	0.0000%	4.31	0.00	4.31
H_2O	18.02	0.0000%	0.1696%	0.0000%	0.1817%	0.00	1.33	1.33
Total	**-**	**100%**	**100%**	**100%**	**100%**	**23,195**	**732**	**23,927**

Actual Stack Temperature[4]	1500 F	816 C	1089 K
Actual Stack Pressure	1 atm	101325 Pa	
Normlized Temperature	32 F	0 C	273 K
Normalized Pressure	1 atm	101325 Pa	
Ideal Gas Constant	8.314 m^3-Pa/mol-K		

Flow Constituent	Flue gas flow[4] (lb-mole/hr)	Flue gas flow (mole/hr)	Mole Fraction (%)	Normalized Flow (Nm^3/hr)	Actual Flow	
					(m^3/hr)	(acfm)
CO_2	539.84	244,866	49.8%	5,485	21,871	12,871
H_2O	106.72	48,406	9.9%	1,084	4,324	2,544
N_2	414.86	188,174	38.3%	4,215	16,808	9,891
O_2	21.99	9,973	2.0%	223	891	524
TOTAL	**1,083.40**	**491,420**	**100.0%**	**11,008**	**43,893**	**25,831**

Pollutant Type	Pollutant	Emission Factor[5,6,7]			Average Hourly Emission Rate[8,9] (lb/hr)	Annual Emissions (tpy)
		ppmvd @3% O_2	mg/Nm^3	lb/MMBtu		
Criteria	NO_x	40	74	-	1.80	7.87
	CO	-	62	-	1.50	6.59
	VOC	-	-	-	0.18	0.77
	PM	-	10	-	0.24	1.06
	PM_{10}	-	10	-	0.24	1.06
	$PM_{2.5}$	-	10	-	0.24	1.06
	SO_2	-	-	-	7.56	33.10
HAPs	Benzene	-	-	-	0.0011	0.0046
	Formaldehyde	-	-	0.000081	0.0012	0.0054
	n-Hexane	-	-	-	0.0015	0.0068
	Toluene	-	-	-	0.00040	0.0018
	Xylene	-	-	-	0.00046	0.0020
	Total HAPs		**-**	**-**	**0.0047**	**0.021**
Non-HAP TACs	H_2S	5	6.9	-	0.17	0.96
Greenhouse Gas	CO_2	-	-	-	23,758.38	136,848.28
	N_2O	-	-	0.00070	0.01	0.05
	CH_4	-	-	-	6.67	29.24

Pollutant Type	Pollutant	Global Warming Potential (GWP)	Average Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
Greenhouse Gas (CO_2e)	CO_2	1	23,758	136,848
	N_2O	298	3.1	14
	CH_4	25	166.9	731
	Total GHGs	**-**	**23,928.40**	**137,593**

Notes:
1. Combined flow to oxidizer.
2. Engineering estimates
3. Engineering estimates
4. Engineering estimates
5. NOx emission factor (in ppmvd @ 3%O2) based on engineering estimates.
6. CO and PM emission factors and H_2S emission factor (in ppmvd @ 3%O2) based on enginnering estimates.
7. Formaldehyde and N_2O emissions factors from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
8. Emission rates for VOC, CH_4, and individual HAPs (except formaldehyde) calculated from total feed rate and rated HC destruction efficiency.
9. SO_2 emission rate based on conversion of H_2S in total feed rate except for the H_2S assumed to be released to the stack (i.e., 5 ppmvd @ 3%O_2).

Table 6
Emissions for Auxiliary Boiler
Magnolia LNG

Parameter	Average Feed Gas Base Case	Rich Feed Gas Case	Ship Loading Case	High Inerts Feed Gas Case	TOTAL	Units
Combustion Gas Fuel Flow Rate (HHV)	84.74	99.91	94.33	82.87	-	MMBtu/hr
Percentage of Operation	90.00%	3.52%	5.48%	1.00%	-	%
Yearly Operation	7884	308	480	88	8760	hr/yr

Pollutant Type	Pollutant	Emission Rate by Case (lb/hr)				Average Hourly Emission Rate (lb/hr)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
		Average Feed Gas Base Case	Rich Feed Gas Case	Ship Loading Case	High Inerts Feed Gas Case			
Criteria	NO_x	4.54	4.97	5.66	5.31	4.62	5.66	20.24
	CO	4.60	5.04	5.74	5.39	4.69	5.74	20.54
	VOC	0.42	0.50	0.47	0.4143	0.43	0.50	1.88
	PM	0.42	0.50	0.47	0.41	0.43	0.50	1.88
	PM_{10}	0.42	0.50	0.47	0.41	0.43	0.50	1.88
	$PM_{2.5}$	0.42	0.50	0.47	0.41	0.43	0.50	1.88
	SO_2	0.02	0	0	0.02	0.02	0.02	0.09
HAPs	Benzene	0.007	0.03	0.01	0	0.01	0.03	0.03
	Ethylbenzene	0	0.004	0	0	0.0001	0.004	0.0005
	Formaldehyde	0.004	0.00	0.01	0.003	0.004	0.01	0.02
	n-Hexane	0.072	0.12	0.05	0.0002	0.07	0.12	0.31
	Toluene	0.003	0.01	0.00	0	0.003	0.01	0.01
	Xylene	0.004	0.00	0.00	0	0.003	0.004	0.02
	Total HAPs	**0.09**	**0.16**	**0.07**	**0.003**	**0.09**	**0.16**	**0.40**
Greenhouse Gas	CO_2	11,378.67	13,885.63	12,544.62	11,297.60	11,530.00	13,885.63	50,501.40
	N_2O	0.42	0.80	0.39	0.52	0.43	0.80	1.90
	CH_4	0.25	0.09	0.34	0.43	0.25	0.43	1.11

Pollutant Type	Pollutant	Global Warming Potential (GWP)	Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
Greenhouse Gas (CO_2e)	CO_2	1	13,885.63	50,501.40
	N_2O	298	239.06	565.07
	CH_4	25	10.71	27.82
	Total GHGs	**-**	**14,135.40**	**51,094.29**

Table 7
Auxiliary Boiler - Case 1 - Avg Feed Gas Base Case
Magnolia LNG

Parameter	HCL Vap Rich Gas	N2 Reject	Feed Gas	TOTAL
Boiler Feed Rate[1] (kg/hr)	769	2181	721	**3671**
Boiler Feed Rate (lb/hr)	1695	4808	1590	**8093**
LHV[1] (kcal/kg)	11090	2072	11520	**24682**
Heat Rate (kcal/hr)	8528210	4519032	8305920	**21353162**
Heat Rate (MMBtu/hr)	33.84	17.93	32.96	**84.74**
HC Desctruction Efficiency[2]	-	-	-	**99.99%**

Component	Component MW (lb/lbmole)	Molar (Volume) Fraction[1] (mol %)			Weight Fraction (wgt %)			Feed Rate (lb/hr)				Feed Rate (lbmole/hr)
		HCL Vap	N2 Reject	Feed Gas	HCL Vap	N2 Reject	Feed Gas	HCL Vap	N2 Reject	Feed Gas	TOTAL	TOTAL
Carbon Dioxide	44.01	0.00%	0.00%	0.01%	0.00%	0.00%	0.03%	0.00	0.00	0.42	0.42	0.01
Nitrogen	28.01	0.00%	68.14%	1.01%	0.00%	78.88%	1.68%	0.02	3792.68	26.78	3819.48	136.34
Methane	16.04	16.78%	31.86%	95.61%	3.89%	21.12%	91.34%	65.89	1015.60	1451.89	2533.37	157.91
Ethane	30.07	4.65%	0.00%	2.56%	2.02%	0.00%	4.58%	34.22	0.00	72.86	107.09	3.56
Propane	44.10	2.17%	0.00%	0.32%	1.38%	0.00%	0.84%	23.46	0.00	13.36	36.82	0.83
i-Butane	58.12	1.55%	0.00%	0.09%	1.30%	0.00%	0.31%	22.07	0.00	4.95	27.02	0.46
n-Butane	58.12	2.35%	0.00%	0.09%	1.97%	0.00%	0.31%	33.40	0.00	4.95	38.35	0.66
i-Pentane	72.15	6.86%	0.00%	0.08%	7.14%	0.00%	0.34%	121.12	0.00	5.46	126.59	1.75
n-Pentane	72.15	12.60%	0.00%	0.08%	13.13%	0.00%	0.34%	222.56	0.00	5.46	228.02	3.16
n-Hexane	86.18	33.90%	0.00%	0.03%	42.18%	0.00%	0.15%	715.05	0.00	2.45	717.49	8.33
Benzene	78.11	3.70%	0.00%	0.00%	4.17%	0.00%	0.00%	70.78	0.00	0.00	70.78	0.91
Cyclohexane	84.16	1.33%	0.00%	0.00%	1.62%	0.00%	0.00%	27.42	0.00	0.00	27.42	0.33
n-Heptane	100.21	7.17%	0.00%	0.01%	10.38%	0.00%	0.06%	175.91	0.00	0.95	176.86	1.76
Toluene	92.14	1.41%	0.00%	0.00%	1.88%	0.00%	0.00%	31.83	0.00	0.00	31.83	0.35
n-Octane	114.23	4.14%	0.00%	0.00%	6.83%	0.00%	0.00%	115.85	0.00	0.00	115.85	1.01
p-Xylene	106.17	1.38%	0.00%	0.00%	2.11%	0.00%	0.00%	35.77	0.00	0.00	35.77	0.34
Ethylbenzene	106.17	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00	0.00
Total	**-**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**1,695**	**4,808**	**1,590**	**8,093**	**317.72**

Stack Parameter[3]	Normalized		Actual	
	(Nm^3/hr)	(scfm)	(m^3/hr)	(acfm)
Stack Flow	32,149	19,027	49,682	29,403

Stack Parameter[3]	Vol %
	(%)
O2	2.30%

Pollutant Type	Pollutant	Emission Factor[4,5,6] (lb/MMBtu)				Stack Concentration			Emission Rate[8] (lb/hr)			
		HCL Vap	N2 Reject	Feed Gas	All	ppm (3% O2)[7]	ppm	mg/Nm^3	HCL Vap	N2 Reject	Feed Gas	TOTAL
Criteria	NO_x	-	-	-	-	30	31.18	64.02	-	-	-	**4.54**
	CO	-	-	-	-	50	51.96	64.95	-	-	-	**4.60**
	VOC	-	-	-	0.005	-	-	-	-	-	-	**0.42**
	PM	-	-	-	0.005	-	-	-	-	-	-	**0.42**
	PM_{10}	-	-	-	0.005	-	-	-	-	-	-	**0.42**
	$PM_{2.5}$	-	-	-	0.005	-	-	-	-	-	-	**0.42**
	SO_2	-	-	0.00065	-	-	-	-	-	-	0.02	**0.02**
HAPs	Benzene	-	-	-	-	-	-	-	0.007	0.000	0.000	**0.007**
	Ethylbenzene	-	-	-	-	-	-	-	0.000	0.000	0.000	**0.000**
	Formaldehyde	-	0.000081	0.000081	-	-	-	-	-	0.001	0.003	**0.004**
	n-Hexane	-	-	-	-	-	-	-	0.072	0.000	0.000	**0.072**
	Toluene	-	-	-	-	-	-	-	0.003	0.000	0.000	**0.003**
	Xylene	-	-	-	-	-	-	-	0.004	0.000	0.000	**0.004**
	Total HAPs		**-**	**-**	-	-	-	-	**0.085**	**0.001**	**0.003**	**0.090**
Greenhouse Gas	CO_2	140	130	130	-	-	-	-	4,745	2,338	4,296	**11,379**
	N_2O	0.0088	0.0024	0.0024	-	-	-	-	0.30	0.04	0.08	**0.42**
	CH_4	-	-	-	-	-	-	-	0.007	0.10	0.15	**0.25**

Notes:

1. Engineering estimates.
2. Engineering estimates.
3. Engineering estimates.
4. Emissions factors for HCL Vap from USEPA AP-42 - Section 1.5 - Liquefied Petroleum Gas Combustion. Emission factors for butane industrial boilers. Emission factors converted from units of lb/1000-gal to lb/MMBtu by dividing by 102 MMBtu/1000-gal (for butane).
5. Emissions factors for N2 Reject and Feed Gas from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
6. Emissions factors for all streams based on engineering estimates.
7. Stack concentrations based on engineering estimates.
8. Emission rates for CH_4, and individual HAPs (except formaldehyde) calculated from total feed rate and rated HC destruction efficiency.

Table 8
Auxiliary Boiler - Case 2 - Rich Feed Gas Case
Magnolia LNG

Parameter	Vap. HCL	N2 Reject	TOTAL
Boiler Feed Rate[1] (kg/hr)	1990	1500	**3490**
Boiler Feed Rate (lb/hr)	4387	3307	**7694**
LHV[1] (kcal/kg)	11090	2072	**13162**
Heat Rate (kcal/hr)	22069100	3108000	**25177100**
Heat Rate (MMBtu/hr)	87.58	12.33	**99.91**
HC Desctruction Efficiency[2]	-	-	**99.99%**

Component	Component MW (lb/lbmole)	Molar (Volume) Fraction[1] (mol %)		Weight Fraction (wgt %)		Feed Rate (lb/hr)			Feed Rate (lbmole/hr)
		HCL Vap	N2 Reject	HCL Vap	N2 Reject	HCL Vap	N2 Reject	TOTAL	TOTAL
Carbon Dioxide	44.01	0.00%	0.00%	0.00%	0.00%	0.01	0.00	0.01	0.00
Nitrogen	28.01	0.00%	68.14%	0.00%	78.88%	0.03	2608.41	2608.44	93.11
Methane	16.04	14.67%	31.86%	3.68%	21.12%	161.46	698.52	859.98	53.60
Ethane	30.07	8.00%	0.00%	3.76%	0.00%	165.16	0.00	165.16	5.49
Propane	44.10	5.74%	0.00%	3.96%	0.00%	173.80	0.00	173.80	3.94
i-Butane	58.12	3.72%	0.00%	3.38%	0.00%	148.32	0.00	148.32	2.55
n-Butane	58.12	5.72%	0.00%	5.20%	0.00%	228.05	0.00	228.05	3.92
i-Pentane	72.15	8.87%	0.00%	10.00%	0.00%	438.90	0.00	438.90	6.08
n-Pentane	72.15	15.43%	0.00%	17.41%	0.00%	763.98	0.00	763.98	10.59
n-Hexane	86.18	19.86%	0.00%	26.77%	0.00%	1174.65	0.00	1174.65	13.63
Benzene	78.11	5.64%	0.00%	6.89%	0.00%	302.19	0.00	302.19	3.87
Cyclohexane	84.16	1.91%	0.00%	2.51%	0.00%	110.18	0.00	110.18	1.31
n-Heptane	100.21	7.28%	0.00%	11.41%	0.00%	500.50	0.00	500.50	4.99
Toluene	92.14	1.46%	0.00%	2.10%	0.00%	92.09	0.00	92.09	1.00
n-Octane	114.23	0.73%	0.00%	1.30%	0.00%	57.10	0.00	57.10	0.50
p-Xylene	106.17	0.49%	0.00%	0.81%	0.00%	35.38	0.00	35.38	0.33
Ethylbenzene	106.17	0.49%	0.00%	0.81%	0.00%	35.38	0.00	35.38	0.33
Total	**-**	**100%**	**100%**	**100%**	**100%**	**4,387**	**3,307**	**7,694**	**205.27**

Stack Parameter[3]	Normalized		Actual	
	(Nm^3/hr)	(scfm)	(m^3/hr)	(acfm)
Stack Flow	34,721	20,549	53,657	31,756

Stack Parameter[3]	Vol %
	(%)
O2	2.03%

Pollutant Type	Pollutant	Emission Factor[4,5,6] (lb/MMBtu)			Stack Concentration			Emission Rate[8] (lb/hr)		
		HCL Vap	N2 Reject	All	ppm (3% O2)[7]	ppm	mg/Nm^3	HCL Vap	N2 Reject	TOTAL
Criteria	NO_x	-	-	-	30	31.63	64.96	-	-	**4.97**
	CO	-	-	-	50	52.72	65.90	-	-	**5.04**
	VOC	-	-	0.005	-	-	-	-	-	**0.50**
	PM	-	-	0.005	-	-	-	-	-	**0.50**
	PM_{10}	-	-	0.005	-	-	-	-	-	**0.50**
	$PM_{2.5}$	-	-	0.005	-	-	-	-	-	**0.50**
	SO_2	-	-	-	-	-	-	-	-	**0.00**
HAPs	Benzene	-	-	-	-	-	-	0.030	0.000	**0.030**
	Ethylbenzene	-	-	-	-	-	-	0.004	0.000	**0.004**
	Formaldehyde	-	0.000081	-	-	-	-	-	0.001	**0.001**
	n-Hexane	-	-	-	-	-	-	0.117	0.000	**0.117**
	Toluene	-	-	-	-	-	-	0.009	0.000	**0.009**
	Xylene	-	-	-	-	-	-	0.004	0.000	**0.004**
	Total HAPs		**-**	-	-	-	-	**0.164**	**0.001**	**0.165**
Greenhouse Gas	CO_2	140	130	-	-	-	-	12,278	1,608	**13,886**
	N_2O	0.0088	0.0024	-	-	-	-	0.77	0.03	**0.80**
	CH_4	-	-	-	-	-	-	0.016	0.07	**0.09**

Notes:

1. Engineering estimates.
2. Engineering estimates.
3. Engineering estimates.
4. Emissions factors for HCL Vap from USEPA AP-42 - Section 1.5 - Liquefied Petroleum Gas Combustion. Emission factors for butane industrial boilers. Emission factors converted from units of lb/1000-gal to lb/MMBtu by dividing by 102 MMBtu/1000-gal (for butane).
5. Emissions factors for N2 Reject from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
6. Emissions factors for all streams based on engineering estimates.
7. Stack concentrations based on engineering estimates.
8. Emission rates for CH_4, and individual HAPs (except formaldehyde) calculated from total feed rate and rated HC destruction efficiency.

Table 9
Auxiliary Boiler - Case 3 - Ship Loading Case
Magnolia LNG

Parameter	Vap. HCL	N2 Reject	TOTAL
Boiler Feed Rate[1] (kg/hr)	574	8400	**8974**
Boiler Feed Rate (lb/hr)	1265	18519	**19784**
LHV[1] (kcal/kg)	11090	2072	**13162**
Heat Rate (kcal/hr)	6365660	17404800	**23770460**
Heat Rate (MMBtu/hr)	25.26	69.07	**94.33**
HC Desctruction Efficiency[2]	-	-	**99.99%**

Component	Component MW (lb/lbmole)	(Volume) Fraction[1] (mol %)		Weight Fraction (wgt %)		Feed Rate (lb/hr)			Feed Rate (lbmole/hr)
		HCL Vap	N2 Reject	HCL Vap	N2 Reject	HCL Vap	N2 Reject	TOTAL	TOTAL
Carbon Dioxide	44.01	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
Nitrogen	28.01	0.00%	71.98%	0.00%	81.77%	0.01	15142.33	15142.34	540.54
Methane	16.04	16.76%	28.02%	3.88%	18.23%	49.16	3376.48	3425.64	213.53
Ethane	30.07	4.65%	0.00%	2.02%	0.00%	25.58	0.00	25.58	0.85
Propane	44.10	2.18%	0.00%	1.39%	0.00%	17.55	0.00	17.55	0.40
i-Butane	58.12	1.56%	0.00%	1.31%	0.00%	16.55	0.00	16.55	0.28
n-Butane	58.12	2.36%	0.00%	1.98%	0.00%	25.11	0.00	25.11	0.43
i-Pentane	72.15	7.08%	0.00%	7.38%	0.00%	93.38	0.00	93.38	1.29
n-Pentane	72.15	13.18%	0.00%	13.74%	0.00%	173.88	0.00	173.88	2.41
n-Hexane	86.18	32.77%	0.00%	40.80%	0.00%	516.26	0.00	516.26	5.99
Benzene	78.11	3.64%	0.00%	4.11%	0.00%	52.02	0.00	52.02	0.67
Cyclohexane	84.16	1.33%	0.00%	1.62%	0.00%	20.47	0.00	20.47	0.24
n-Heptane	100.21	7.33%	0.00%	10.60%	0.00%	134.18	0.00	134.18	1.34
Toluene	92.14	1.45%	0.00%	1.93%	0.00%	24.40	0.00	24.40	0.26
n-Octane	114.23	4.28%	0.00%	7.06%	0.00%	89.31	0.00	89.31	0.78
p-Xylene	106.17	1.42%	0.00%	2.18%	0.00%	27.60	0.00	27.60	0.26
Ethylbenzene	106.17	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
Total	-	**100%**	**100%**	**100%**	**100%**	**1,265**	**18,519**	**19,784**	**769.28**

Stack Parameter[3]	Normalized (Nm^3/hr)	(scfm)	Actual (m^3/hr)	(acfm)
Stack Flow	38,633	22,864	59,703	35,334

Stack Parameter[3]	Vol % (%)
O2	1.60%

Pollutant Type	Pollutant	Factor[4,5,6] (lb/MMBtu)			Concentration			Rate[8] (lb/hr)		
		HCL Vap	N2 Reject	All	ppm (3% O2)[7]	ppm	mg/Nm^3	HCL Vap	N2 Reject	TOTAL
Criteria	NO_x	-	-	-	30	32.35	66.44	-	-	**5.66**
	CO	-	-	-	50	53.92	67.40	-	-	**5.74**
	VOC	-	-	0.005	-	-	-	-	-	**0.47**
	PM	-	-	0.005	-	-	-	-	-	**0.47**
	PM_{10}	-	-	0.005	-	-	-	-	-	**0.47**
	$PM_{2.5}$	-	-	0.005	-	-	-	-	-	**0.47**
	SO_2	-	-	-	-	-	-	-	-	**0.00**
HAPs	Benzene	-	-	-	-	-	-	0.005	0.000	**0.005**
	Ethylbenzene	-	-	-	-	-	-	0.000	0.000	**0.000**
	Formaldehyde	-	0.000081	-	-	-	-	-	0.006	**0.006**
	n-Hexane	-	-	-	-	-	-	0.052	0.000	**0.052**
	Toluene	-	-	-	-	-	-	0.002	0.000	**0.002**
	Xylene	-	-	-	-	-	-	0.003	0.000	**0.003**
	Total HAPs		**-**	-	-	-	-	**0.062**	**0.006**	**0.068**
Greenhouse Gas	CO_2	140	130	-	-	-	-	3,541	9,003	**12,545**
	N_2O	0.0088	0.0024	-	-	-	-	0.22	0.17	**0.39**
	CH_4	-	-	-	-	-	-	0.005	0.34	**0.34**

Notes:

1. Engineering estimates.
2. Engineering estimates.
3. Engineering estimates.
4. Emissions factors for HCL Vap from USEPA AP-42 - Section 1.5 - Liquefied Petroleum Gas Combustion. Emission factors for butane industrial boilers. Emission factors converted from units of lb/1000-gal to lb/MMBtu by dividing by 102 MMBtu/1000-gal (for butane).
5. Emissions factors for N2 Reject from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
6. Emissions factors for all streams based on engineering estimates.
7. Stack concentrations based on engineering estimates.
8. Emission rates for CH_4, and individual HAPs (except formaldehyde) calculated from total feed rate and rated HC destruction efficiency.

Table 10
Auxiliary Boiler - Case 4 - High Inerts Feed Gas Case
Magnolia LNG

Parameter	N2 Reject	Feed Gas	TOTAL
Boiler Feed Rate[1] (kg/hr)	6120	712	**6832**
Boiler Feed Rate (lb/hr)	13492	1570	**15062**
LHV[1] (kcal/kg)	2072	11520	**13592**
Heat Rate (kcal/hr)	12680640	8202240	**20882880**
Heat Rate (MMBtu/hr)	50.32	32.55	**82.87**
HC Desctruction Efficiency[2]	-	-	**99.99%**

Component	Component MW (lb/lbmole)	Molar (Volume) Fraction[1] (mol %)		Weight Fraction (wgt %)		Feed Rate (lb/hr)			Feed Rate (lbmole/hr)
		N2 Reject	Feed Gas	N2 Reject	Feed Gas	N2 Reject	Feed Gas	TOTAL	TOTAL
Carbon Dioxide	44.01	0.00%	0.0100%	0.00%	0.03%	0.00	0.41	0.41	0.01
Nitrogen	28.01	68.15%	1.0100%	78.88%	1.68%	10643.18	26.45	10669.63	380.88
Methane	16.04	31.85%	95.6100%	21.12%	91.34%	2849.09	1433.76	4282.85	266.96
Ethane	30.07	0.00%	2.5600%	0.00%	4.58%	0.00	71.95	71.96	2.39
Propane	44.10	0.00%	0.3200%	0.00%	0.84%	0.00	13.19	13.19	0.30
i-Butane	58.12	0.00%	0.0900%	0.00%	0.31%	0.00	4.89	4.89	0.08
n-Butane	58.12	0.00%	0.0900%	0.00%	0.31%	0.00	4.89	4.89	0.08
i-Pentane	72.15	0.00%	0.0800%	0.00%	0.34%	0.00	5.40	5.40	0.07
n-Pentane	72.15	0.00%	0.0800%	0.00%	0.34%	0.00	5.40	5.40	0.07
n-Hexane	86.18	0.00%	0.0300%	0.00%	0.15%	0.00	2.42	2.42	0.03
Benzene	78.11	0.00%	0.0000%	0.00%	0.00%	0.00	0.00	0.00	0.00
Cyclohexane	84.16	0.00%	0.0000%	0.00%	0.00%	0.00	0.00	0.00	0.00
n-Heptane	100.21	0.00%	0.0100%	0.00%	0.06%	0.00	0.94	0.94	0.01
Toluene	92.14	0.00%	0.0000%	0.00%	0.00%	0.00	0.00	0.00	0.00
n-Octane	114.23	0.00%	0.0000%	0.00%	0.00%	0.00	0.00	0.00	0.00
p-Xylene	106.17	0.00%	0.0000%	0.00%	0.00%	0.00	0.00	0.00	0.00
Ethylbenzene	106.17	0.00%	0.0000%	0.00%	0.00%	0.00	0.00	0.00	0.00
Total	-	**100%**	**100%**	**100%**	**100%**	**13,492**	**1,570**	**15,062**	**650.89**

Stack Parameter[3]	Normalized		Actual	
	(Nm^3/hr)	(scfm)	(m^3/hr)	(acfm)
Stack Flow	37,118	21,968	57,361	33,948

Stack Parameter[3]	Vol % (%)
O2	2.03%

Pollutant Type	Pollutant	Emission Factor[4,5,6] (lb/MMBtu)			Stack Concentration			Emission Rate[8] (lb/hr)		
		N2 Reject	Feed Gas	All	ppm (3% O2)[7]	ppm	mg/Nm^3	HCL Vap	N2 Reject	TOTAL
Criteria	NO_x	-	-	-	30	31.63	64.95	-	-	**5.31**
	CO	-	-	-	50	52.71	65.89	-	-	**5.39**
	VOC	-	-	0.005	-	-	-	-	-	**0.41**
	PM	-	-	0.005	-	-	-	-	-	**0.41**
	PM_{10}	-	-	0.005	-	-	-	-	-	**0.41**
	$PM_{2.5}$	-	-	0.005	-	-	-	-	-	**0.41**
	SO_2	-	0.00065	-	-	-	-	-	0.02	**0.02**
HAPs	Benzene	-	-	-	-	-	-	0.000	0.000	**0.000**
	Ethylbenzene	-	-	-	-	-	-	0.000	0.000	**0.000**
	Formaldehyde	-	0.000081	-	-	-	-	-	0.003	**0.003**
	n-Hexane	-	-	-	-	-	-	0.000	0.000	**0.000**
	Toluene	-	-	-	-	-	-	0.000	0.000	**0.000**
	Xylene	-	-	-	-	-	-	0.000	0.000	**0.000**
	Total HAPs		**-**	-	-	-	-	**0.000**	**0.003**	**0.003**
Greenhouse Gas	CO_2	140	130	-	-	-	-	7,055	4,243	**11,298**
	N_2O	0.0088	0.0024	-	-	-	-	0.44	0.08	**0.52**
	CH_4	-	-	-	-	-	-	0.285	0.14	**0.43**

Notes:

1. Engineering estimates.
2. Engineering estimates.
3. Engineering estimates.
4. Emissions factors for HCL Vap from USEPA AP-42 - Section 1.5 - Liquefied Petroleum Gas Combustion. Emission factors for butane industrial boilers. Emission factors converted from units of lb/1000-gal to lb/MMBtu by dividing by 102 MMBtu/1000-gal (for butane).
5. Emissions factors for N2 Reject and Feed Gas from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
6. Emissions factors for all streams based on engineering estimates.
7. Stack concentrations based on engineering estimates.
8. Emission rates for CH_4, and individual HAPs (except formaldehyde) calculated from total feed rate and rated HC destruction efficiency.

Table 11
Emissions for Ammonia Vent
Magnolia LNG

Parameter	Purge
Stack Rate (kg/hr)	130.45
Stack Rate (lb/hr)	287.59
Hours of Operation (hr/yr)	438

Component	Component MW (lb/lbmole)	Weight Fraction (wgt %)	Molar (Volume) Fraction[1] (mol %)	Feed Rate (lb/hr)		Annual Emissions
		Purge	Purge	kg/hr	lb/hr	(tpy)
Ammonia	17.03	2.3%	3.6%	3.00	6.61	1.45
Nitrogen	27.01	96.2%	94.2%	125.49	276.66	60.59
H2O	18.02	1.5%	2.2%	1.96	4.31	0.94
Total	**-**	**100.0%**	**100.0%**	**130.45**	**287.59**	**62.98**

Actual Stack Temperature[4]	68 F	20 C	293 K
Actual Stack Pressure	1 atm	101325 Pa	
Normlized Temperature	32 F	0 C	273 K
Normalized Pressure	1 atm	101325 Pa	
Ideal Gas Constant	8.314 m^3-Pa/mol-K		

Flow Constituent	Flue gas flow[4] (lb-mole/hr)	Flue gas flow (mole/hr)	Mole Fraction (%)	Normalized Flow (Nm^3/hr)	Actual Flow	
					(m^3/hr)	(acfm)
Ammonia	0.39	176	3.6%	3.9	4.2	2.5
Nitrogen	10.24	4,646	94.2%	104.1	111.7	65.7
H2O	0.24	109	2.2%	2.4	2.6	1.5
TOTAL	**10.87**	**4,930**	**100.0%**	**110.4**	**119**	**70**

Table 12
Emissions for Warm Flare
Magnolia LNG

Parameter	Units	Pilot Gas	Release	Max
Combustion Gas Fuel Flow Rate[1] (mass)	kg/hr	7.33	60,000	60,007
	lb/hr	16.16	132,276	132,292
Combustion Gas Molecular Weight	g/mol	16.82	16.82	16.82
Combustion Gas Fuel Flow Rate[1] (volume)	Nm^3/hr	9.76	79,923	79,933
	scf/hr	345	2,822,077	2,822,421
Combustion Gas Higher Heating Value[2]	kcal/kg	11,520	11,520	11,520
	J/mol	811,093	811,093	811,093
Combustion Gas Fuel Heat Rate	kcal/hr	84,442	691,200,000	691,284,442
	MMBtu/hr	0.34	2742.68	2,743
Yearly Operation	hr/yr	8760	88	8,760
HC Desctruction Efficiency	%	99.5%	99.5%	99.5%

Normlized Temperature	32 F	0 C	273 K
Normalized Pressure	1 atm	101325 Pa	
Ideal Gas Constant	8.314 m^3-Pa/mol-K		

		Pilot Gas			Release		
Component	Molecular Weight (lb/lbmole)	Molar (Volume) Fraction (mol %)	Weight Fraction (wgt %)	Feed Rate (lb/hr)	Molar (Volume) Fraction (mol %)	Weight Fraction (wgt %)	Feed Rate (lb/hr)
Carbon Dioxide	44.01	0.0005%	0.00%	0.00	0.0005%	0.00%	1.73
Nitrogen	28.01	1.0153%	1.69%	0.27	1.0153%	1.69%	2237.20
Methane	16.04	95.7069%	91.31%	14.75	95.7069%	91.31%	120775.57
Ethane	30.07	2.5625%	4.58%	0.74	2.5625%	4.58%	6061.03
Propane	44.10	0.3249%	0.85%	0.14	0.3249%	0.85%	1126.96
i-Butane	58.12	0.0914%	0.32%	0.05	0.0914%	0.32%	417.88
n-Butane	58.12	0.0914%	0.32%	0.05	0.0914%	0.32%	417.88
i-Pentane	72.15	0.0812%	0.35%	0.06	0.0812%	0.35%	460.84
n-Pentane	72.15	0.0812%	0.35%	0.06	0.0812%	0.35%	460.84
n-Hexane	86.18	0.0305%	0.16%	0.03	0.0305%	0.16%	206.75
Benzene	78.11	0.0031%	0.01%	0.00	0.0031%	0.01%	19.05
Cyclohexane	84.16	0.0010%	0.01%	0.00	0.0010%	0.01%	6.62
n-Heptane	100.21	0.0051%	0.03%	0.00	0.0051%	0.03%	40.20
Toluene	92.14	0.0010%	0.01%	0.00	0.0010%	0.01%	7.25
n-Octane	114.23	0.0031%	0.02%	0.00	0.0031%	0.02%	27.85
p-Xylene	106.17	0.0010%	0.01%	0.00	0.0010%	0.01%	8.35
Ethylbenzene	106.17	0.0000%	0.00%	0.00	0.0000%	0.00%	0.00
Total	**-**	**100%**	**100%**	**16.16**	**100%**	**100%**	**132,276**
Stream Molecular Weight (g/mol)		16.82			16.82		

		Emission Factor[3,4]	Emission Rate (lb/hr)			Annual Emissions (tpy)			PTE (tpy)
Pollutant Type	Pollutant	(lb/MMBtu)	Pilot Gas	Release	MAX	Pilot Gas	Release	TOTAL	TOTAL
Criteria	NO_x	0.068	0.02	186.50	**186.53**	0.10	8.21	**8.31**	**816.98**
	CO	0.37	0.12	1,014.79	**1,014.92**	0.54	44.65	**45.19**	**4,445.33**
	VOC	-	0.002	16.23	**16.23**	0.01	0.71	**0.72**	**71.08**
	PM	0.0083	0.003	22.76	**22.77**	0.01	1.00	**1.01**	**99.72**
	PM_{10}	0.0083	0.003	22.76	**22.77**	0.01	1.00	**1.01**	**99.72**
	$PM_{2.5}$	0.0083	0.003	22.76	**22.77**	0.01	1.00	**1.01**	**99.72**
HAPs	Benzene	-	0.00001	0.10	**0.10**	0.00005	0.004	**0.004**	**0.42**
	Formaldehyde	0.000081	0.00003	0.22	**0.22**	0.0001	0.01	**0.010**	**0.98**
	Hexane	-	0.0001	1.03	**1.03**	0.0006	0.05	**0.05**	**4.53**
	Toluene	-	0.000004	0.04	**0.04**	0.00002	0.002	**0.002**	**0.16**
	Xylene	-	0.00001	0.04	**0.04**	0.00002	0.002	**0.002**	**0.18**
	Total HAPs		**0.00**	**1.43**	**1.43**	**0.0008**	**0.06**	**0.06**	**6.27**
Non-HAP TACs	H_2S								
Greenhouse Gas	CO_2	130	43.56	356,548.61	**356,592.17**	190.79	15,688.14	**15,878.92**	**1,561,873.69**
	N_2O	0.00022	0.00007	0.60	**0.60**	0.0003	0.03	**0.03**	**2.64**
	CH_4	-	0.074	603.88	**603.95**	0.32	26.57	**26.89**	**2,645.31**

		Global Warming Potential	Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)	
Pollutant Type	Pollutant	(GWP)	MAX	Actual	PTE
Greenhouse Gas (CO_2e)	CO_2	1	356,592.17	15,878.92	1,561,873.69
	N_2O	298	179.83	8.01	787.66
	CH_4	25	15,098.79	672.34	66,132.70
	Total GHGs	**-**	**371,870.79**	**16,559.28**	**1,628,794.06**

Notes:

1. Engineering estimates.
2. Engineering estimate.
3. NO_x and CO emission factors from United States Environmental Protection Agency (EPA) AP 42 Fifth Edition, Volume I - Section 13.5 - "Industrial Flares".
4. CO_2, formaldehye, and PM emissions factors from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.
5. N_2O emission factors from 40 CFR 98 Table C-2 to Subpart C - Natural Combustion.

Table 13
Emissions for Cold Flare
Magnolia LNG

Parameter	Units	Pilot Gas	Release	Max
Combustion Gas Fuel Flow Rate[1] (mass)	kg/hr	7.33	40,000	40,007
	lb/hr	16.16	88,184	88,200
Combustion Gas Molecular Weight	g/mol	16.82	18.42	18.42
Combustion Gas Fuel Flow Rate[1] (volume)	Nm^3/hr	9.76	48,652	48,662
	scf/hr	345	1,717,898	1,718,243
Combustion Gas Higher Heating Value[2]	kcal/kg	11,520	9,288	9,289
	J/mol	811,093	716,204	716,236
Combustion Gas Fuel Heat Rate	kcal/hr	84,442	371,533,692	371,618,134
	MMBtu/hr	0.34	1474.25	1,475
Yearly Operation	hr/yr	8760	88	8,760
HC Desctruction Efficiency	%	99.5%	99.5%	99.5%

Normlized Temperature	32 F	0 C	273 K
Normalized Pressure	1 atm	101325 Pa	
Ideal Gas Constant	8.314 m^3-Pa/mol-K		

		Pilot Gas			Release		
Component	Molecular Weight (lb/lbmole)	Molar (Volume) Fraction (mol %)	Weight Fraction (wgt %)	Feed Rate (lb/hr)	Molar (Volume) Fraction (mol %)	Weight Fraction (wgt %)	Feed Rate (lb/hr)
Carbon Dioxide	44.01	0.0005%	0.00%	0.00	0.0000%	0.00%	0.00
Nitrogen	28.01	1.0153%	1.69%	0.27	19.8300%	30.16%	26598.80
Methane	16.04	95.7069%	91.31%	14.75	80.1700%	69.84%	61585.20
Ethane	30.07	2.5625%	4.58%	0.74	0.0000%	0.00%	0.00
Propane	44.10	0.3249%	0.85%	0.14	0.0000%	0.00%	0.00
i-Butane	58.12	0.0914%	0.32%	0.05	0.0000%	0.00%	0.00
n-Butane	58.12	0.0914%	0.32%	0.05	0.0000%	0.00%	0.00
i-Pentane	72.15	0.0812%	0.35%	0.06	0.0000%	0.00%	0.00
n-Pentane	72.15	0.0812%	0.35%	0.06	0.0000%	0.00%	0.00
n-Hexane	86.18	0.0305%	0.16%	0.03	0.0000%	0.00%	0.00
Benzene	78.11	0.0031%	0.01%	0.00	0.0000%	0.00%	0.00
Cyclohexane	84.16	0.0010%	0.01%	0.00	0.0000%	0.00%	0.00
n-Heptane	100.21	0.0051%	0.03%	0.00	0.0000%	0.00%	0.00
Toluene	92.14	0.0010%	0.01%	0.00	0.0000%	0.00%	0.00
n-Octane	114.23	0.0031%	0.02%	0.00	0.0000%	0.00%	0.00
p-Xylene	106.17	0.0010%	0.01%	0.00	0.0000%	0.00%	0.00
Ethylbenzene	106.17	0.0000%	0.00%	0.00	0.0000%	0.00%	0.00
Total	**-**	**100%**	**100%**	**16.16**	**100%**	**100%**	**88,184**
Stream Molecular Weight (g/mol)		16.82			18.42		

		Emission Factor[3,4]	Emission Rate (lb/hr)			Annual Emissions (tpy)			PTE (tpy)
Pollutant Type	Pollutant	(lb/MMBtu)	Pilot Gas	Release	MAX	Pilot Gas	Release	TOTAL	TOTAL
Criteria	NO_x	0.068	0.02	100.25	**100.27**	0.10	4.41	**4.51**	**439.19**
	CO	0.37	0.12	545.47	**545.59**	0.54	24.00	**24.54**	**2,389.71**
	VOC	-	0.002	0.12	**0.12**	0.009	0.005	**0.01**	**0.53**
	PM	0.0083	0.003	12.24	**12.24**	0.01	0.54	**0.55**	**53.61**
	PM_{10}	0.0083	0.003	12.24	**12.24**	0.01	0.54	**0.55**	**53.61**
	$PM_{2.5}$	0.0083	0.003	12.24	**12.24**	0.01	0.54	**0.55**	**53.61**
HAPs	Benzene	-	0.00001	0	**0.00001**	0.00005	0	**0.00005**	**0.00005**
	Formaldehyde	0.000081	0.00003	0.12	**0.12**	0.0001	0.01	**0.01**	**0.53**
	Hexane	-	0.0001	0	**0.0001**	0.0006	0	**0.0006**	**0.0006**
	Toluene	-	0.000004	0	**0.000004**	0.00002	0	**0.00002**	**0.00002**
	Xylene	-	0.00001	0	**0.00001**	0.00002	0	**0.00002**	**0.00002**
	Total HAPs		**0.00**	**0.12**	**0.12**	**0.0008**	**0.01**	**0.01**	**0.53**
Non-HAP TACs	H_2S								
Greenhouse Gas	CO_2	130	43.56	191,651.94	**191,695.50**	190.79	8,432.69	**8,623.47**	**839,626.28**
	N_2O	0.00022	0.00007	0.32	**0.32**	0.0003	0.01	**0.01**	**1.42**
	CH_4	-	0.074	307.93	**308.00**	0.32	13.55	**13.87**	**1,349.04**

		Global Warming Potential	Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)	
Pollutant Type	Pollutant	(GWP)	MAX	Actual	PTE
Greenhouse Gas (CO_2e)	CO_2	1	191,695.50	8,623.47	839,626.28
	N_2O	298	96.67	4.35	423.43
	CH_4	25	7,699.99	346.80	33,725.98
	Total GHGs	**-**	**199,492.17**	**8,974.62**	**873,775.69**

Notes:

1. Engineering estimates.
2. Engineering estimate.

3. NO_x and CO emission factors from United States Environmental Protection Agency (EPA) AP 42 Fifth Edition, Volume I - Section 13.5 - "Industrial Flares".

4. CO_2, formaldehye, and PM emissions factors from USEPA AP-42 - Section 1.4 - Natural Gas Combustion. Emissions converted from units of lb/MMscf to lb/MMBtu by dividing by 1020 MMBtu/MMscf. Emission factor also multiplied by HHV/LHV ratio of 1.108.

5. N_2O emission factors from 40 CFR 98 Table C-2 to Subpart C - Natural Combustion.

Table 14
Emissions for Emergency Generator Engine
Magnolia LNG

Parameter	Value	Units
Fuel	diesel	-
Power Rating	1000	kW
	1341	hp
Fuel Flow[1]	71.9	gal/hr
Heating Value of Low-Sulfur Diesel	129,488	Btu/gal
Engine Heat Rate	9.31	MMBtu/hr
Maximum Yearly Operation	500	hr/yr

Pollutant Type	Pollutant	Emission Factor[2,3] (lb/MMBtu)	Emission Factor[4,5] (g/hp-hr)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
Criteria	NO_x	-	4.8	14.19	3.55
	CO	-	2.6	7.69	1.92
	VOC	-	0.48	1.42	0.35
	PM	-	0.15	0.44	0.11
	PM_{10}	-	0.12	0.36	0.09
	$PM_{2.5}$	-	0.10	0.30	0.08
	SO_2	0.001515	-	0.01	0.004
HAPs	Benzene	0.000776	-	0.01	0.002
	Toluene	0.000281	-	0.003	0.0007
	Total HAPs	**-**	**-**	**0.01**	**0.002**
Greenhouse Gas	CO_2	165	-	1,536.18	384.05
	N_2O	0.00132		0.01	0.003
	CH_4	0.0081	-	0.08	0.02

Pollutant Type	Pollutant	Global Warming Potential (GWP)	Maximum Hourly Emission Rate (lb CO_2e/hr)	Annual Emissions (ton CO_2e/yr)
Greenhouse Gas (CO_2e)	CO_2	1	1,536.18	384.05
	N_2O	298	3.67	0.92
	CH_4	25	1.89	0.47
	Total GHGs	**-**	**1,541.74**	**385.43**

Notes:

1. Based on representative engine.

2. Emission factors (except for N_2O) from USEPA AP 42 Section 3.4 - Large Stationary Diesel and All Stationary Dual-Fuel Engines. October 1996. SO2 emission factor based on low sulfur diesel with 0.0015% sulfur content (15 ppm).

3. N_2O emission factor based on 40 CFR 98 Table C-2 to Subpart C.

4. NO_x, CO, VOC, and PM emission factors based on Non-Road Tier 2 standards as required under NSPS Subpart IIII. NO_x emission factor equal to NOx+NMHC emission standard. VOC emission factor equal to 10% of NOx+NMHC emission standard.

5. PM_{10} and $PM_{2.5}$ emission factors derived from PM emission factors using pariculate size ratios in USEPA AP 42 Section 3.4 - Large Stationary Diesel and All Stationary Dual-feul Engines. October 1996.

Table 15
Emissions for Emergency Fire Pump
Magnolia LNG

Parameter	Value	Units
Fuel	diesel	-
Power Rating	250	kW
	355	hp
Fuel Flow[1]	18.6	gal/hr
Heating Value of Low-Sulfur Diesel	129,488	Btu/gal
Engine Heat Rate	2.41	MMBtu/hr
Maximum Yearly Operation	500	hr/yr

Pollutant Type	Pollutant	Emission Factor[2,3,4] (lb/MMBtu)	Emission Factor[5,6] (g/hp-hr)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
Criteria	NO_x	-	3.0	2.35	0.59
	CO	-	2.6	2.03	0.51
	VOC	-	0.3	0.23	0.06
	PM	-	0.15	0.12	0.03
	PM_{10}	-	0.12	0.10	0.02
	$PM_{2.5}$	-	0.10	0.08	0.02
	SO_2	0.001515	-	0.004	0.0009
HAPs	Benzene	0.000933	-	0.002	0.0006
	Formaldehyde	0.00118	-	0.0028	0.0007
	Total HAPs	**-**	**-**	**0.005**	**0.001**
Greenhouse Gas	CO_2	164	-	394.99	98.75
	N_2O	0.00132		0.003	0.001
	CH_4	0.0081	-	0.02	0.00

Pollutant Type	Pollutant	Global Warming Potential (GWP)	Maximum Hourly Emission Rate (lb CO_2e/hr)	Annual Emissions (ton CO_2e/yr)
Greenhouse Gas (CO_2e)	CO_2	1	394.99	98.75
	N_2O	298	0.95	0.24
	CH_4	25	0.49	0.12
	Total GHGs	**-**	**396.43**	**99.11**

Notes:

1. Based on representative engine.

2. Individual HAP and CO_2 emission factors from USEPA AP 42 Section 3.3 - Gasoline and Diesel Industrial Engines.

3. SO_2 and CH_4 emission factors from USEPA AP 42 Section 3.4 - Large Stationary Diesel and All Stationary Dual-Fuel Engines. SO2 emission factor based on low sulfur diesel with 0.0015% sulfur content (15 ppm).

4. N_2O emission factor based on 40 CFR 98 Table C-2 to Subpart C.

5. NO_x, CO, and VOC emission factors based on Non-Road Tier 3 standards as required under NSPS Subpart IIII. NO_x emission factor equal to NOx+NMHC emission standard. VOC emission factor equal to 10% of NOx+NMHC emission standard.

6. PM emission factors based on Non-Road Tier 2 standards as required under NSPS Subpart IIII. PM_{10} and $PM_{2.5}$ emission factors derived from PM emission factors using pariculate size ratios in USEPA AP 42 Section 3.4 - Large Stationary Diesel and All Stationary Dual-Fuel Engines.

Table 16
Emissions for Deluge Pump
Magnolia LNG

Parameter	Value	Units
Fuel	diesel	-
Power Rating	600	kW
	801	hp
Fuel Flow[1]	37.9	gal/hr
Heating Value of Low-Sulfur Diesel	129,488	Btu/gal
Engine Heat Rate	4.91	MMBtu/hr
Maximum Yearly Operation	500	hr/yr

Pollutant Type	Pollutant	HHV Emission Factor[2,3] (lb/MMBtu)	Emission Factor[4,5] (g/hp-hr)	Maximum Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
Criteria	NO_x	-	4.8	8.48	2.12
	CO	-	2.6	4.59	1.15
	VOC	-	0.48	0.85	0.21
	PM	-	0.15	0.26	0.07
	PM_{10}	-	0.12	0.22	0.05
	$PM_{2.5}$	-	0.10	0.18	0.05
	SO_2	0.001515	-	0.007	0.002
HAPs	Benzene	0.000776	-	0.004	0.001
	Total HAPs	**-**	**-**	**0.004**	**0.001**
Greenhouse Gas	CO_2	164	-	804.85	201.21
	N_2O	0.00132		0.01	0.002
	CH_4	0.0081	-	0.04	0.01

Pollutant Type	Pollutant	Global Warming Potential (GWP)	Maximum Hourly Emission Rate (lb CO_2e/hr)	Annual Emissions (ton CO_2e/yr)
Greenhouse Gas (CO_2e)	CO_2	1	804.85	201.21
	N_2O	298	1.93	0.48
	CH_4	25	0.99	0.25
	Total GHGs	**-**	**807.77**	**201.94**

Notes:

1. Based on representative engine.

2. Emission factors from USEPA AP 42 Section 3.4 - Large Stationary Diesel and All Stationary Dual-Fuel Engines. October 1996. SO2 emission factor based on low sulfur diesel with 0.0015% sulfur content (15 ppm).

3. N_2O emission factor based on 40 CFR 98 Table C-2 to Subpart C.

4. NO_x, CO, VOC, and PM emission factors based on Non-Road Tier 2 standards as required under NSPS Subpart IIII. NO_x emission factor equal to NOx+NMHC emission standard. VOC emission factor equal to 10% of NOx+NMHC emission standard.

5. PM_{10} and $PM_{2.5}$ emission factors derived from PM emission factors using pariculate size ratios in USEPA AP 42 Section 3.4 - Large Stationary Diesel and All Stationary Dual-feul Engines. October 1996.

Table 19 - LNG Vessel and Tug Boat Operational Emissions

SLOW SPEED DIESEL without reliquefaction

		Nat Gas	Units	Tugs Diesel	Units	Oil	Units
Emission	NOx	1.3	g/kW-hr	13.2	g/kW-hr	13.6	g/kW-hr
Factors	CO	1.1	g/kW-hr	1.1	g/kW-hr	1.4	g/kW-hr
	VOC	0.5	g/kW-hr	0.5	g/kW-hr	0.6	g/kW-hr
	PM10	0.05	g/kW-hr	0.72	g/kW-hr	0.19	g/kW-hr
	PM2.5	0.05	g/kW-hr	0.72	g/kW-hr	0.17	g/kW-hr
	(Tug factor based on ULSD marine diesel) SO2	0.05	g/kW-hr	0.0065	g/kW-hr	0.36	g/kW-hr
	CO2	420	g/kW-hr	690	g/kW-hr	588.79	g/kW-hr
	N2O			0.02	g/kW-hr	0.031	g/kW-hr
	CH4			0.09	g/kW-hr	0.006	g/kW-hr

Assumptions

LNG Carrier speed at rated power = 19 knots

LNG Vessel oil Efs from Table 2-9 ICF Report for slow speed diesel, marine gas oil 0.1% sulfur. Nat Gas factors from Wartsila for 50DF and American Shipping Bureau

95% Nat Gas/5% MGO used on inbound and outbound trip in propulsion engines - revised based on info from MAN diesel regarding ME-GI propulsion

99% Nat Gas/1% MGO used in generator set engine for Hoteling

Tug boat emission factor based on Cat 2 Engine, Tier 0, Table 3-8 ICF Report. SO2 factor corrected to 500 ppm fuel S.

0.8 Per Table 2-12 ICF Report, NOx adjustment factor for oil use in ECA for 2015 for main engines

0.1 Estimated effect of Nonroad fuel requirement on sulfur content after June 1, 2007 (90% reduction).

While hoteling, assume aux engine uses on MGO, propulsion engines shutdown.

Annual Carrier dockings (175K m3 vessel)	104	berthings/yr	berthings based on 2/week as stated in RR1
Annual Barge dockings (15K m3 barge)	104	berthings/yr	berthings based on 2/week as stated in RR1

Total Power LNG Carrier	30,575 bhp	22,800 kW	LNG power based on typical 175K m3 DFDE LNG carrier
Total Power (2 assist Tugs)	12,000 bhp	8,948 kW	
Total Power (1 assist Tug)	6,000 bhp	4,474 kW	

LNG Carrier and Assist Tugs

Vessel	Activity	Duration (hr)	Engine Use (%)	Total Engine Rating (bhp)	Total Engine Rating (kW)	Natural Gas Flow (MMBtu/hr)	Activity Emissions (lb) NOx	CO	VOC	PM10	PM2.5	SO2	CH4	N2O	CO2	Annual Emissions (tpy) NOx	CO	VOC	PM10	PM2.5	SO2	CH4	N2O	CO2
LNG Carrier	10.4 n. miles out to shore @ 12 knots	0.9	80%	24460	18240	178.6	69	40	18	2	2	2	0	0	15505	3.6	2.1	1.0	0.1	0.1	0.1	0.0	0.0	806
Inbound	Shore up Calcasieu to Devil's Elbow 19 n. miles @ avg 6 knots	3.2	50%	15288	11400	111.6	154	90	41	5	5	5	0	0	34457	8.0	4.7	2.1	0.2	0.2	0.3	0.0	0.0	1792
95%Natural Gas	Maneuvering from Devil's Elbow to berth 3 n. mi. @ 3 kts including turn around	2.0	25%	7644	5700	55.8	48	28	13	1	1	2	0	0	10768	2.5	1.5	0.7	0.1	0.1	0.1	0.0	0.0	560
5% marine gas oil	**Subtotal**	**6.1**	-	-	-	-	**271**	**158**	**72**	**8**	**8**	**9**	**0**	**0**	**60730**	**14.1**	**8.2**	**3.7**	**0.4**	**0.4**	**0.5**	**0.0**	**0.0**	**3158**
	Hoteling while loading	**18.0**	10%	3057.5	2280	n/a	1230	127	54	17	15	33	1	1	53271	64.0	6.6	2.8	0.9	0.8	1.7	0.0	0.0	2770
LNG Carrier	Maneuvering away from dock (straight out) to Devil's Elbow 3 n. mi. @ 3 kts	1.0	25%	7643.75	5700	55.8	24	14	6	1	1	1	0	0	5384	1.3	0.7	0.3	0.0	0.0	0.0	0.0	0.0	280
Outbound	Transit from Devil's Elbow to Gulf shore line 19 n.mi. @avg 6 kts	3.2	50%	15287.5	11400	111.6	154	90	41	5	5	5	0	0	34457	8.0	4.7	2.1	0.2	0.2	0.3	0.0	0.0	1792
95%Natural Gas	Shore to 10.4 n. miles out @ 12 knots	0.9	80%	24460	18240	178.6	69	40	18	2	2	2	0	0	15505	3.6	2.1	1.0	0.1	0.1	0.1	0.0	0.0	806
5% marine gas oil	**Subtotal**	**5.1**					**247**	**144**	**65**	**7**	**7**	**8**	**0**	**0**	**55346**	**12.9**	**7.5**	**3.4**	**0.4**	**0.4**	**0.4**	**0.0**	**0.0**	**2878**
	2 tugs transit from port to meet Carrier offshore (32 n. miles @ 10 kts)	3.2	80%	9600	7159	n/a	667	56	25	36	36	0	5	1	34847	34.7	2.9	1.3	1.9	1.9	0.0	0.2	0.1	1812
Tug Boats	2 tugs transit alongside Carrier to Port (32.4 n. Miles) @ avg 8 kts.	4.1	70%	8400	6264	n/a	747	62	28	41	41	0.4	5.1	1.1	39067	38.9	3.2	1.5	2.1	2.1	0.0	0.3	0.1	2031
	2 addnl tugs transit out to meet Carrier at 3.04 n. mi. from Magnolia @ 10 kts.	0.3	80%	9600	7159	n/a	62	5	2	3	3	0.0	0.4	0.1	3267	3.2	0.3	0.1	0.2	0.2	0.0	0.0	0.0	170
	4 tugs transit alongside Carrier for 3.04 n. mi. to Magnolia @ 3.5 kts.	0.9	50%	12000	8948	n/a	227	19	9	12	12	0.1	1.5	0.3	11843	11.8	1.0	0.4	0.6	0.6	0.0	0.1	0.0	616
Diesel	4 tugs assist carrier dock at Magnolia	1.0	90%	21600	16107	n/a	469	39	18	26	26	0.2	3.2	0.7	24502	24.4	2.0	0.9	1.3	1.3	0.0	0.2	0.0	1274
	1 tug standby during loading	17.5	10%	600	447	n/a	228	19	9	12	12	0.1	1.6	0.3	11911	11.8	1.0	0.4	0.6	0.6	0.0	0.1	0.0	619
	4 tugs full power push/tow away from dock	1.0	90%	21600	16107	n/a	469	39	18	26	26	0.2	3.2	0.7	24502	24.4	2.0	0.9	1.3	1.3	0.0	0.2	0.0	1274
	4 tugs transit alongside Carrier to 3.04 n. mi. to Magnolia @ 3.5 kts.	0.9	50%	12000	8948	n/a	227	19	9	12	12	0.1	1.5	0.3	11843	11.8	1.0	0.4	0.6	0.6	0.0	0.1	0.0	616
	2 addnl tugs transit to port from Carrier at 3.04 n. mi. from Magnolia @ 10 kts.	0.3	80%	9600	7159	n/a	62	5	2	3	3	0.0	0.4	0.1	3267	3.2	0.3	0.1	0.2	0.2	0.0	0.0	0.0	170
	2 tugs transit alongside Carrier to release offshore (32 n. Miles)	4.1	70%	8400	6264	n/a	747	62	28	41	41	0.4	5.1	1.1	39067	38.9	3.2	1.5	2.1	2.1	0.0	0.3	0.1	2031
	2 tugs transit from release of Carrier to port	3.2	80%	9600	7159	n/a	667	56	25	36	36	0.3	5	1	34847	34.7	2.9	1.3	1.9	1.9	0.0	0.2	0.1	1812
	Subtotal	**36.4**					**4571.4**	**381.0**	**173.2**	**249**	**249**	**2.3**	**31.2**	**6.9**	**238960**	**237.7**	**19.8**	**9.0**	**13.0**	**13.0**	**0.0**	**1.6**	**0.4**	**12426**
Barge Loading	Tug boat maneuvering barge to dock	**1.0**	90%	5400	4026.78	n/a	117	10	4	6	6	0	0.8	0.2	6125	6.1	0.5	0.2	0.3	0.3	0.0	0.0	0.0	319
One Tug Boat	Tug boat standby while barge loaded	**2.0**	10%	600	447.42	n/a	26	2	1	1	1	0	0.2	0.0	1361	1.4	0.1	0.1	0.1	0.1	0.0	0.0	0.0	71
	Tug boat maneuvering barge away from dock	**1.0**	90%	5400	4026.78	n/a	117	10	4	6	6	0	0.8	0.2	6125	6.1	0.5	0.2	0.3	0.3	0.0	0.0	0.0	319
	Subtotal						**260**	**22**	**10**	**14**	**14**	**0**	**2**	**0**	**13612**	**13.5**	**1.1**	**0.5**	**0.7**	**0.7**	**0.0**	**0.1**	**0.0**	**708**
TOTAL							**6581**	**831**	**374**	**296**	**294**	**53**	**34**	**8**	**421919**	**342.2**	**43.2**	**19.5**	**15.4**	**15.3**	**2.6**	**1.7**	**0.4**	**21940**

Table 20 - Operational Mobile Sources - Magnolia LNG

Source	Emission Factors												
	NOx	CO	VOC	PM	PM10	PM2.5	SO2	CO2	CO2e	CH4	N2O	Units	Emission Factor Source
Worker Commutes	0.089	1.177	0.015	0.011	0.011	0.005	0.004	n/a	172	n/a	n/a	g/mile	USEPA MOVES model run for Calcasieu Parish
Tug/barge LNG Distribution	13.200	1.100	0.500	0.720	0.720	0.720	0.007	690	n/a	0.09	0.02	g/kw-hr	7000 hp (5220 kW) tug, EF from ICF USEPA Ports Emission Factor report
Truck Distribution	2.376	0.597	0.100	0.122	0.122	0.097	0.011	n/a	1045	n/a	n/a	g/mile	USEPA MOVES model run for Calcasieu Parish

Source	Activity Data per RT	Activity units	Number of Trips	Frequency	Frequency Units	Activity per time unit	Activity per year	Hours per year	Number of Trips Data Source
Worker Commutes	40	miles	40	1	day	1600	584000	n/a	Magnolia Traffic Study, October 2013, page 22.
Tug/barge LNG Distribution	15	hours	2	1	week	n/a	n/a	1560	RR1: up to 2 tug/barges per week. Assume maximum RT distance 45 n. miles @3 knots maximum
Truck Distribution	38	miles	1	1	week	38	1976	n/a	RR1: current potential is one truck trip per week. Miles from site to I-10 per traffic study likely route.

Source	Emissions (tons)										
	NOx	CO	VOC	PM	PM10	PM2.5	SO2	CO2	CO2e	CH4	N2O
Worker Commutes	0.057	0.758	0.010	0.007	0.007	0.003	0.003	n/a	110	n/a	n/a
Tug/barge LNG Distribution	52.49	4.37	1.99	2.86	2.86	2.86	0.03	2744	2776	0.358	0.080
Truck Distribution	0.005	0.001	0.000	0.000	0.000	0.000	0.000	n/a	2	n/a	n/a
Total	**52.6**	**5.1**	**2.0**	**2.9**	**2.9**	**2.9**	**0.0**	**2743.7**	**2889.1**	**0.4**	**0.1**

Appendix 9.B.2

Fugitive Emissions Calculations

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Appendix 9.C
Air Modeling Protocols and Associated Correspondence

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Appendix 9.C.1

Air Quality Modeling Protocol

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January 16, 2014

Via Email and UPS

Tegan Treadaway
Louisiana Department of Environmental Quality
Air Quality Supervisor
P.O. Box 4313
Baton Rouge, LA 70821-4313

Re: Magnolia LNG Air Quality Modeling Protocol

Dear Tegan,

Magnolia LNG, LLC (Magnolia) is pleased to submit the enclosed Air Quality Modeling Protocol for LDEQ's review. Magnolia has prepared the protocol to describe the methods, pre and post-processing programs, and model to be used to determine the proposed Magnolia LNG Project's impact compared to significant impact levels (SILs), the significant monitoring concentration (SMC) and, for impacts above applicable SILs, to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) Increment levels.

We appreciate LDEQ's review of our modeling protocol. Should you have any questions or require any additional information, please do not hesitate to contact myself at 713-815-6930 or khassan@magnolialng.com; Bruce Wattle at 716-684-8060 ext. 2572 or bwattle@ene.com; or Bill Daughdrill at 850-435-8925 ext. 4303 or wdaughdrill@ene.com.

Thank you,

Komi O. Hassan

Komi Hassan
EH&S Manager
Magnolia LNG

Enclosure:

cc: Bryan Johnston, Yvette Olmos

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MAGNOLIA LNG PROJECT

Air Quality Modeling Protocol

15 January 2014

Submitted to:

Louisiana Department of Environmental Quality

Submitted by:

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Prepared by:

ecology and environment, inc.
Global Environmental Specialists

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APPENDIX

A Preliminary Operational Emission Estimates

ACRONYMS AND ABBREVIATIONS

BACT	Best Available Control Technology
BPIP-PRIME	Building Profile Input Program with Prime
BTEX	benzene, toluene, ethylbenzene, and xylene
Btu	British thermal unit
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2e	carbon dioxide equivalent
DEM	digital elevation models
DLE	dry-low emissions
GHG	greenhouse gas
KMLP	Kinder Morgan Louisiana Pipeline
LAC	Louisiana Administrative Code
LDEQ	Louisiana Department of Environmental Quality
LNG	liquefied natural gas
m^3	cubic meter(s)
Magnolia	Magnolia LNG, LLC
mtpa	million (metric) tonnes per annum
NAAQS	National Ambient Air Quality Standards
NNSR	nonattainment new source review
NO_2	nitrogen dioxide
NO_X	nitrogen oxide
NOAA	National Oceanic and Atmospheric Administration
NSR	New Source Review
OSMR®	Optimized Single Mixed Refrigerant
PM_{10}	particulate matter equal to or less than 10 micrometers aerodynamic diameter
$PM_{2.5}$	particulate matter equal to or less than 2.5 micrometers aerodynamic diameter
Port	Lake Charles Harbor & Terminal District

Project	Magnolia LNG Project
PSD	Prevention of Significant Deterioration
PTE	potential to emit
PVMRM	plume volume molar ratio method
SIL	significant impact level
SMC	significant monitoring concentration
TAP	toxic air pollutant
tpy	tons per year
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compounds

1 INTRODUCTION

1.1 OBJECTIVE

Magnolia LNG, LLC (Magnolia) has prepared this protocol to describe the methods, pre- and post-processing programs, and model to be used to determine the proposed Magnolia LNG Project's impact compared to significant impact levels (SILs), the significant monitoring concentration (SMC) and, for impacts above applicable SILs, to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) Increment levels. The protocol is based on the current United States Environmental Protection Agency's (USEPA's) Guideline on Air Quality Models (USEPA 2005), the USEPA's New Source Review Workshop Manual (1990), various recent USEPA memoranda regarding modeling procedures for short term standards analysis, and the Louisiana Department of Environmental Quality's (LDEQ's) Air Quality Modeling Procedures (the latter as updated by discussions with LDEQ) (LDEQ 2006).

1.2 PROJECT DESCRIPTION

Magnolia is proposing to develop a natural gas liquefaction facility in Lake Charles, Calcasieu Parish, Louisiana, on a currently vacant site. Calcasieu Parish is located in the Southern Louisiana-Southeast Texas Interstate Air Quality Control Region. Calcasieu Parish is designated as attainment/unclassifiable for all criteria pollutants.

The Magnolia LNG Project (referred to herein as the Project) facility would be capable of producing a nominal capacity of approximately 8.0 million (metric) tonnes per annum (mtpa) of liquefied natural gas (LNG). Magnolia would use its highly efficient and patented Optimized Single Mixed Refrigerant (OSMR®) technology to produce LNG. The Project would receive natural gas via an existing pipeline that passes beneath the Project site near the southern boundary. Associated with the Project, Kinder Morgan Louisiana Pipeline (KMLP) would develop a compressor station in Eunice Louisiana, approximately 52 miles from the Project site. Permitting and any modeling required for the KMLP Eunice compressor station would be undertaken directly by KMLP.

The natural gas would be treated, liquefied, and stored on site in two full containment LNG storage tanks with a net pumpable capacity of approximately 160,000 cubic meters (m^3) each. At full plant capacity, the Project would consist of four LNG trains each with a nominal capacity of 2.0 mtpa of LNG (total nominal capacity of approximately 8.0 mtpa). The LNG would be loaded onto LNG carriers for export overseas; LNG carriers and barges for domestic marine distribution and the possibility of LNG bunkering; and LNG trucks for road distribution to LNG refueling stations in Louisiana and the surrounding states.

1.3 FACILITY LOCATION AND PRELIMINARY SITE LAYOUT

The Project would be located on the Industrial Canal South Shore Port of Lake Charles Tract 475, an approximately 115-acre parcel of land in Calcasieu Parish, south of Lake Charles,

available through a long-term lease with the Lake Charles Harbor & Terminal District (the Port). The Industrial Canal is located off the main Calcasieu River Ship Channel. The Project would be located in an area zoned for heavy industrial use and would be consistent with other industrial facilities along the shoreline. The coordinates of the proposed Project site are as follows: Latitude: 30° 06′ 20.30″ N; Longitude: 93° 17′54.00″ W. Figure 1 is a general location map of the Project.

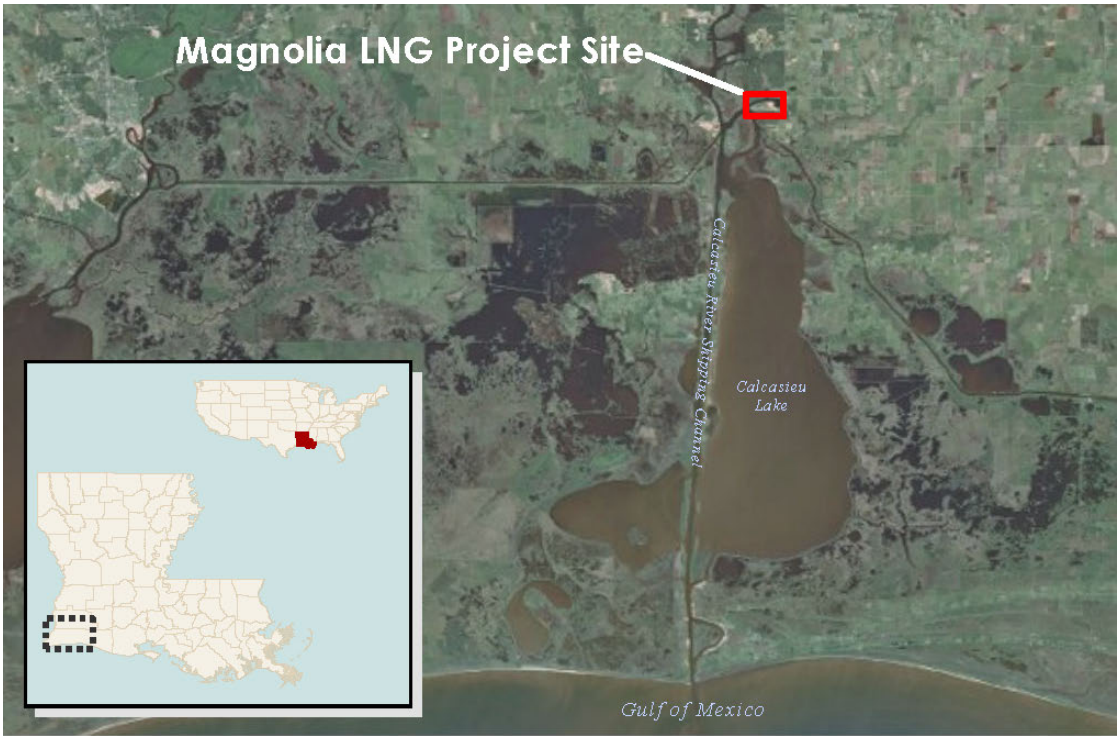


Figure 1 General Location Map of the Magnolia LNG Project

On March 6, 2013, Magnolia signed an exclusive and binding four-year Real Estate Lease Option Agreement (Option Agreement) with the Port for the Project site. The Option Agreement includes a clause for a 30-year-term ground lease option with the right to extend the lease term for four periods of 10 years each, for a total of 70 years. The expected operational life of the Project is a minimum of 30 years. Figure 2 shows the boundary of the lease area.

Magnolia has prepared a preliminary layout of equipment on the leased area. Figure 3 shows the location of the emission sources to be modeled for the Project analysis and air permit application.



Figure 2 Project Site Boundary Map



Figure 3 Preliminary Site Layout Showing Potential Emission Source Locations

1.4 SOURCE DESIGNATION

Initial potential to emit (PTE) estimates and Project location in an attainment area for all criteria pollutants indicate that a PSD modeling analysis will be required for the criteria pollutants nitrogen dioxide (NO_2), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter equal to or less than 10 micrometers aerodynamic diameter (PM_{10}), and particulate matter equal to or less than 2.5 micrometers aerodynamic diameter ($PM_{2.5}$). Emissions of greenhouse gas (GHG) also would be above PSD major source thresholds; however, GHGs are not currently subject to modeling requirements. Initial PTE for the Project is shown in Table 1. Emission calculation details are provided in Appendix A of this protocol.

Table 1 Preliminary Potential Operation Emissions (tons per year) for the Project

Emission Source	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC	HAPs	CO_2e
Gas Turbines (8)	1,016	639	32	74	74	45	11	1,318,269
Thermal Oxidizers (4)	18	30	0.2	3	3	2	1	42,725
Auxiliary Boiler (4)	83	139	1	13	13	9	4	198,469
Emergency Generator	1.5	3.0	0.0	0.02	0.02	0.7	0.13	249
Emergency Fire Water Pump	0.7	1.5	0.0	0.01	0.01	0.4	0.06	125
Flares	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Project Total	**1,119**	**813**	**33**	**90**	**90**	**57**	**16**	**1,559,837**
PSD Threshold	**250**	**250**	**250**	**250**	**250**	**250**	**N/A**	**100,000**
Trigger PSD?	**YES**	**YES**	**NO**	**NO**	**NO**	**NO**	**N/A**	**YES**
Significant Emission Rate	**40**	**100**	**40**	**15**	**10**	**40**	**N/A**	**N/A**
PSD Modeling Required?	**YES**	**YES**	**NO**	**YES**	**YES**	**YES**	**N/A**	**N/A**

Key:
CO = carbon monoxide.
CO_2e = carbon dioxide equivalent.
HAPs = hazardous air pollutants.
N/A = Not applicable.
NO_X = nitrogen oxide.
PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.
$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.
PSD = Prevention of Significant Deterioration.
SO_2 = sulfur dioxide.
TBD = To be determined.
VOC = volatile organic compound.

2 APPLICABLE PERMITTING REGULATIONS AND SHORT-TERM MODELING GUIDANCE

2.1 NEW SOURCE REVIEW

New Source Review (NSR) refers to the preconstruction permitting programs under Parts C and D of the Clean Air Act. NSR must be addressed before construction can begin on new major sources or major modifications to existing major sources. The PSD program is the NSR permitting program for sources located in attainment areas (below the NAAQS) and unclassified areas (areas for which there is insufficient information to determine attainment status). For sources located in nonattainment areas, the NSR permitting program is the nonattainment new source review (NNSR) program. Emission source thresholds for nonattainment areas are lower than the emission source thresholds for attainment areas. The Project location is unclassifiable/ attainment and, therefore, is compared to attainment area major source NSR thresholds.

The major source attainment area NSR thresholds are either 100 tons per year (tpy) or 250 tpy. The 100 tpy threshold applies only to 28 distinct source categories listed in 40 Code of Federal Regulations (CFR) 52.21. The Project does not belong to any of the 28 source categories; therefore, the applicable major source threshold is 250 tpy per criteria pollutant and 100,000 tpy for carbon dioxide equivalent (CO_2e). Estimated operational emissions would be above 250 tpy for nitrogen oxide (NO_X) and CO and above 100,000 tpy for CO_2e (see Table 1); therefore, the Project is subject to major source NSR attainment area (PSD) permitting.

2.2 SHORT-TERM NAAQS MODELING GUIDANCE

The USEPA has provided guidance for modeling methodology for the 1-hour NO_2 NAAQS in a series of memoranda (USEPA 2010a, 2011). The guidance provided in these memoranda describe procedures for processing and interpreting model results with regards to the statistical form of the 1-hour NO_2 NAAQS. The USEPA has also provided guidance for modeling to demonstrate compliance with the $PM_{2.5}$ NAAQS (USEPA 2010b). Magnolia will follow these procedures when modeling and processing model results.

3 MODELING METHODOLOGY

3.1 CLASS II MODELING GUIDANCE

The approach for the air quality modeling analysis is based on the USEPA's Guideline on Air Quality Models, incorporated as 40 CFR 51, Appendix W (USEPA 2005). Additional guidance documents to be used include the following:

- The LDEQ's Air Quality Modeling Procedures (LDEQ 2006), incorporating changes as discussed with the LDEQ.
- The USEPA memorandum on the guidance concerning the implementation of the 1-hour NO_2 NAAQS for the PSD program (USEPA 2010a).
- The USEPA memorandum on "Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS" (USEPA 2010b).
- The USEPA memorandum on "Draft Guidance for $PM_{2.5}$ Permit Modeling" (USEPA 2013a).
- The USEPA document regarding the "Circuit Court Decision on $PM_{2.5}$ Significant Impact Levels and Significant Monitoring Concentration – Questions and Answers" (USEPA 2013b).

3.2 AIR POLLUTANT STANDARDS AND SIGNIFICANCE IMPACT LEVELS

NAAQS and/or Louisiana ambient air quality standards have been promulgated for the following criteria pollutants: CO, lead, NO_2, ozone, PM_{10}, $PM_{2.5}$, and SO_2. NAAQS and Louisiana ambient air quality standards are summarized in Table 2.

Table 3 summarizes PSD class I and II increments, SILs, and monitoring de minimis concentrations.

Table 2 State and National Ambient Air Quality Standards

Pollutant	Averaging Time	NAAQS				Louisiana Air Quality Standards
		Primary		Secondary		
		($\mu g/m^3$)	(ppm)	($\mu g/m^3$)	(ppm)	
CO	8-hour	10,000	9[(a)]	-		Same as Primary NAAQS
	1-hour	40,000	35[(a)]	-		Same as Primary NAAQS
Lead	Rolling 3-month average	0.15	-	Same as Primary NAAQS		Same as Primary NAAQS

Table 2 State and National Ambient Air Quality Standards

Pollutant	Averaging Time	NAAQS				Louisiana Air Quality Standards
		Primary		Secondary		
		($\mu g/m^3$)	(ppm)	($\mu g/m^3$)	(ppm)	
NO_2	Annual	100	0.053	Same as Primary NAAQS		Same as Primary NAAQS
	1-hour	188	0.100	-		-
Ozone	8-hour	147	0.075[(b)]	Same as Primary NAAQS		Same as Primary NAAQS
PM_{10}	24-hour	150[(c)]	-	Same as Primary NAAQS		Same as Primary NAAQS
$PM_{2.5}$	Annual	12.0[(d)]	-	15.0	-	Same as Secondary NAAQS
	24-hour	35[(e)]	-	Same as Primary NAAQS		Same as Primary NAAQS
SO_2	Annual	80[(f)]	-	-	-	Same as Primary NAAQS
	24-hour	365[(f)]	-	-	-	Same as Primary NAAQS
	3-hour	-	-	1,300	0.5	Same as Secondary NAAQS
	1-hour	195	0.075	-	-	Same as Primary NAAQS

Notes:

(a) Not to be exceeded more than once per year.

(b) The 2008 standard. The three-year average of the 4th highest daily maximum 8-hour average concentration over each year must not exceed the standard.

(c) Not to be exceeded more than once per year on average over three years.

(d) The three-year average of the weighted annual mean concentrations must not exceed the standard.

(e) The three-year average of the 98th percentile concentrations must not exceed the standard.

(f) The USEPA revoked the annual and 24-hour standards in the 2010 SO_2 rulemaking establishing the 1-hour standard and retaining the 3-hour secondary standard. However, the annual and 24-hour standards remain in effect until one year after an area is designated for the 2010 standard. The USEPA issued designations on July 25, 2013; therefore, the annual and 24-hour standards remain in effect until July 25, 2014.

Key:

$\mu g/m^3$ = microgram per cubic meter.

CO = carbon dioxide.

NAAQS = National Ambient Air Quality Standards.

PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.

$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.

ppm = parts per million.

SO_2 = sulfur dioxide.

Table 3 Prevention of Significant Deterioration (PSD) Increments, PSD Significant Emission Rates (SERs), Significant Impact Levels (SILs), and Monitoring De Minimis Concentrations Applicable to the Project

Pollutant	Averaging Period	PSD Increments ($\mu g/m^3$) Class I	PSD Increments ($\mu g/m^3$) Class II	PSD SERs (tpy)	SILs ($\mu g/m^3$)	Monitoring De Minimis Concentrations ($\mu g/m^3$)
PM_{10}	24-hour	8[(a)]	30[(a)]	15[(a)]	5	10
$PM_{2.5}$	Annual	1	4	10 of $PM_{2.5}$	0.3	
				40 of SO_2	N/A	
				40 of NO_X[(b)]	N/A	
	24-hour	2	9		1.2	0[(c)]
NO_2	Annual	2.5	25	40 of NO_X	1	14
	1-hour	-[(c)]	-[(c)]		7.5[(c)]	
Ozone	8-hour	-	-	40 of VOC or NO_X	-	VOC or NO_X emissions increase > 100 tpy
CO	8-hour	-	-	100	500	575
	1-hour	-	-		2,000	-

Notes:

(a) In addition to PM_{10}, there is a PSD SER for Total Suspended Particulate (TSP) of 25 tpy.

(b) NO_X emissions regulated unless demonstrated not to be a $PM_{2.5}$ precursor. Ammonia and VOC emissions are presumed not to be precursors. See 73 *Federal Register* 28321 for additional details.

(c) PSD Increments, SIL, and Monitoring De Minimum Concentration level for the 1-hour NO_2 standard has not been finalized. However, an interim SIL of 7.5 µg/m3 for NO_2 was provided by the USEPA in a general guidance implementation memo dated June 28, 2010. The monitoring de minimis concentration for $PM_{2.5}$ was effectively set equal to zero due to the Circuit Court decision on January 22, 2013.

Key:

$\mu g/m^3$ = microgram per cubic meter.

CO = carbon dioxide.

NAAQS = National Ambient Air Quality Standards.

NO_2 = nitrogen dioxide

NO_X = nitrogen oxide

PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.

$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.

ppm = parts per million.

SO_2 = sulfur dioxide.

USEPA = United States Environmental Protection Agency

VOC = volatile organic compounds.

3.3 BACKGROUND AIR POLLUTANT CONCENTRATIONS

For primary air pollutant compounds, i.e., pollutants directly emitted from emission sources, and secondary air pollutants (ozone, formed from the directly emitted pollutants NO_X and VOC), four monitoring stations surround Lake Charles. These are detailed in Table 4 along with the pollutants monitored at each site.

Table 4 Ambient Air Monitoring Stations near Lake Charles

Site	Distance and Direction from Project Site	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC	Ozone
Baton Rouge	130 miles to east	✓	✓	✓	✓	✓		✓
Lafayette	75 miles to east			✓	✓			✓
Carlyss	4.8 miles to northwest							✓
Lake Charles Lighthouse Lane	7.6 miles to north-northwest						✓	
Westlake	11 miles to north		✓		✓	✓	✓	✓
McNeese University	7 miles to northeast				✓			

Source: LDEQ n.d.
Key:
CO = carbon dioxide.
NO_X = nitrogen oxide.
PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.
$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.
SO_2 = sulfur dioxide.
VOC = volatile organic compounds.

Magnolia evaluated the distance, direction, and surroundings of each monitoring site to select the appropriate background monitor data sites. Magnolia proposes to use the Westlake monitor site for background data for NO_X, SO_2, and ozone since it is the closest monitoring site to the Project location where these pollutants are measured and is representative of the Project location. Magnolia proposes to use $PM_{2.5}$ data from the McNeese University site, which is the closest $PM_{2.5}$ monitoring station to the Project location. There are no stations in the Lake Charles vicinity that monitor for CO or PM_{10}; the closest site where PM_{10} is monitored is in Lafayette (approximately 75 miles to the east), and CO is monitored in Baton Rouge (approximately 130 miles to the east). These latter two sites are proposed as PM_{10} and CO background data sites. While relatively distant from the Project location and surrounded by urbanized land development, they likely represent typical PM_{10} and CO concentrations for an urban/developed land type setting similar to the Project location. Due to the central city location of the Baton Rouge CO monitor, a higher influence of vehicle emissions may tend to cause data from this station to be slightly conservative (higher) than the Project site. The appropriate statistical form

of the background concentration data will be obtained from either the LDEQ or the USEPA Airs database. Adjusted background procedures as described in the LDEQ guidance will not be used.

3.4 MODEL SELECTION

The USEPA's AERMOD, Version 13350 (issued December 16, 2013), will be the regulatory dispersion model used to estimate ambient impact concentrations of emissions from the Project sources. Regulatory default options as recommended in the USEPA's Guideline on Air Quality Models will be used in the modeling analysis. The regulatory default option in AERMOD includes the use of stack-tip downwash, incorporates the effects of elevated terrain, and includes the calms and missing data processing routines.

Preprocessing programs associated with AERMOD include AERMAP (version 11103), AERSURFACE (version 13016), AERMET (version 13350) and AERMINUTE (version 11325). These are the most recent versions available. If the USEPA issues updated versions prior to the start of input data preprocessing for the Project, Magnolia will use updated versions.

3.5 SOURCE CHARACTERIZATION

All proposed emission sources will be modeled as point sources. The Project emission source inventory, heat input ratings and anticipated hours of operation are presented in Table 5. Magnolia is working with potential equipment vendors for the auxiliary boiler, thermal oxidizer, emergency use engines for the emergency generator and firewater pump, and for flares to develop final specifications and emission rates. Table 6 shows preliminary stack parameters for the Project emission sources as currently known. Draft emission rates for each source are shown in Appendix A; however, final source characteristics and maximum emission rates to be modeled will represent worst-case conditions and will be presented in the modeling report and permit application after the Best Available Control Technology (BACT) analysis has been completed.

Equipment Description

The gas turbines for the Project will be aero-derivative units produced by General Electric, model PGT25+G4. Each gas turbine will combust only pipeline quality natural gas and will be equipped with dry-low emissions (DLE) and a waste heat recovery unit. Each unit's heat input rating is shown in Table 5.

Magnolia is currently in the process of obtaining proposals from potential auxiliary boiler vendors; therefore, a specific unit has not been selected at this time. The data presented in this protocol are preliminary and subject to change upon final vendor selection. However, the data presented are reasonable approximations of the performance characteristics of the boiler.

Table 5 Emission Source Equipment Inventory – Magnolia LNG Project

Equipment Type	Quantity On-Site	Heat Input Rating (MMBtu/hr)[(a)]	Expected Annual Hours of Operation
Gas Turbine	8	318.42	8,760
Auxiliary Boiler	4	96	8,760
CO_2 Vent/Thermal Oxidizer	4	20.2	8,760
Diesel Engine Firewater Pump	1	1.85	<100
Diesel Engine Emergency Generator	1	7.42	<100
Marine Flare	1	To Come	<100
Process Flare	1	To Come	<100

Note: (a) Based on higher heating value (HHV) of 1,043 Btu/scf.

Key:
Btu/scf = British thermal units per standard cubic foot
CO_2 = carbon dioxide.
MMBtu/hr = million British thermal units per hour.

Table 6 Preliminary Stack Parameter Values for Project Emission Sources

Emission Source	Stack Height (meters)	Stack Diameter (meters)	Exit Velocity (meters per second)	Exit Temperature (degrees Celsius)
Gas Turbine (each)	27	3.3	25	196
Auxiliary Boiler (each)	25	1.2	~15	149
CO_2 Vent/Thermal Oxidizer (each)	23	0.3	TBD	TBD
Cryogenic Flare	33	note 1	20	1,000
Process Flare	33	note 1	20	1,000
Emergency Generator Engine	TBD	TBD	TBD	TBD
Firewater Pump Engine	TBD	TBD	TBD	TBD

Notes:
1) Effective stack diameter to be based on calculation procedure contained in section 5.9.4 of LDEQ 2006 modeling guidance which relates resulting stack diameter to total heat release of gas being flared.

Key:
CO_2 = carbon dioxide
TBD = to be determined

The auxiliary boilers in each liquefaction train would combust a mixture of high British thermal unit (Btu) (feed gas and rich gas) and low Btu (holding and ship loading) fuel using low NO_X burners. The boiler efficiency will be approximately 84 percent. The percentage of each fuel type that would be in the fuel mixture fired in the boiler has not been developed. For the preliminary potential to emit estimate, it is assumed the composition of the fuel gas is primarily feed gas with the waste gas stream from the carbon dioxide removal system. Blending in rich gas and low Btu gas would alter the potential to emit slightly, estimated as varying by no more than 5 to 10 percent. The fuel gas stream burned in the auxiliary boiler may also contain trace amounts of benzene, toluene, ethylbenzene, and xylene (BTEX) from the carbon dioxide removal system. The estimated destruction efficiency for these hazardous air pollutants (HAPs) in the combustion process is 99.99 percent.

The thermal oxidizer would consist of a low NO_X burner firing upward into the base of a leg-supported, refractory-lined incinerator. Contaminated CO_2 (containing BTEX) would enter the unit near the base of the incinerator vessel near the burner. This physical arrangement would allow the burner to use the cool, inert waste gas as a means to reduce NO_X production during operation, resulting in a NO_X concentration of approximately 40 parts per million by dry volume at 3 percent oxygen. The feed gas would mix with the waste gas in the combustion process to form the hot flue gas that would be discharged from the unit at the top. The estimated destruction efficiency for BTEX in the combustion process is 99.00 percent. Other necessary control devices and programming would be provided to ensure that the system would start and operate safely according to National Fire Protection Association 85/86 guidelines. The thermal oxidizer vendor has not been selected at this time.

The marine and process flare will not be used during normal operation; however, a small pilot light will be continuously lit should flaring be needed. Flaring is not used during normal operation because the boil-off-gas generated from the LNG tank will be used as fuel gas in the auxiliary boiler. However, when maintenance is required, process lines may need to be manually vented and purged. There may also be occasions of automated venting from Pressure Relief Valves, Process Shutdowns, and Emergency Shutdown. During these events, flaring will be necessary. Magnolia is developing an estimate of the frequency of flaring that will be included in the final modeling protocol. Modeling guidance for flares from section 5.9.4 of the LDEQ modeling guidance will be used if flares are included in the worst-case modeling condition.

Vendors have not been selected for the emergency generator set or the diesel firewater pump.

3.6 EFFECTS OF NEARBY FACILITIES

Effects of nearby facilities will not be included in the preliminary dispersion modeling analysis for comparison to the SILs. If the preliminary dispersion modeling analysis shows significant impacts, an additional protocol will be submitted for the refined analysis that includes contributions from nearby facilities for comparison to PSD increment consumption.

3.7 TOXIC AIR POLLUTANT ANALYSIS

Louisiana Administrative Code Part III, Chapter 51 addresses emissions and analysis of toxic air pollutants (TAPs). Chapter 51 is applicable to major sources of TAPs, which are defined in Louisiana Administrative Code (LAC) 33:III.5103 as emission of any individual TAP at or above 10 tpy or the combination of all TAPs if equal to or above 25 tpy. The current emission inventory shown in Table 1 shows that total TAPs are estimated at 16 tpy. Emissions of individual TAPs are presented in Appendix A; the single TAP emitted in the largest quantity is formaldehyde at 8.2 tpy. Both the total TAPs and the individual TAP emitted in the largest amount are below the major source applicability thresholds specified in LAC 33:III.5103. Therefore, a TAP analysis for TAPs over the minimum emission rates as specified in LAC 33:III.5112 is not required for the Project. As the emission inventory is finalized, the total TAP and individual TAP emissions will be reviewed in comparison to Chapter 51 major source applicability thresholds. If a modeling analysis for TAPs becomes necessary, a supplement to this Protocol will be provided to the LDEQ.

4 AERMOD MODELING OPTIONS

4.1 BUILDING DOWNWASH

Building downwash effects will be considered in the modeling analysis. Structures and buildings will be included in the analysis when the distance between modeled stacks and the nearest part of the building is less than or equal to five times the lesser of the height or the projected width of the building. The Building Profile Input Program with Prime (BPIP-PRIME) will be used to calculate direction-specific building dimensions and good engineering practice stack heights. AERMOD uses the output from BPIP-PRIME to calculate building downwash effects.

Due to the compact footprint of each liquefaction train, each train will be considered as a solid building for input to BPIP-PRIME. Each liquefaction train has a maximum dimension of approximately 166 meters (545 feet) and minimum dimension of 44 meters (144 feet).

4.2 TERRAIN

The terrain surrounding the proposed Project location up to 50 kilometers in any direction is best described as flat. A preliminary evaluation of terrain heights indicates most terrain elevations are between 0 feet and 20 feet in a 50-kilometer radius; there is a slight rise in elevation to the northwest with terrain reaching 40 to 50 feet at a distance of approximately 35 to 40 kilometers away. According to section 5.7 of the LDEQ Air Quality Modeling Procedures, requirements to consider terrain elevations are determined on a case-by-case basis. For the Project location in the Southwest Regional office region, the LDEQ typically does not require use of terrain data in dispersion modeling. However, after discussion with the LDEQ regarding implementing terrain data in flat terrain areas, Magnolia proposes to use the AERMOD Terrain Preprocessor (AERMAP Version 11103) to assign terrain elevations of source, building, and receptor locations. U.S. Geological Survey (USGS) 7.5-minute digital elevation models (DEMs) would be used for processing in AERMAP. The Project datum would be in North American Datum of 1983-Universal Transverse Mercator coordinates.

4.3 METEOROLOGICAL DATA

AERMOD will be run with surface meteorological data and upper air data from the Lake Charles Regional Airport. The airport is approximately 4.6 miles (7.5 kilometers) east-northeast of the Project site. Surface observation data will be obtained from the National Oceanic and Atmospheric Administration (NOAA) Integrated Surface Database. Upper air data will be obtained from the NOAA Earth System Research Laboratory radiosonde observation database. A five-year dataset will be used, encompassing the period 2008 through 2012. If 2013 data are available for upper air and surface datasets, the five-year dataset will comprise years 2009 through 2013.

The processing steps to be used include determining land surface characteristics followed by processing of the land surface characteristics; surface and upper air meteorological data. The USEPA AERSURFACE program (version 13016) will be used to determine the surface

characteristics surrounding the Project site. AERSURFACE processes land cover data to determine the surface characteristics for use in AERMET. AERSURFACE uses a 1-kilometer radius surrounding the site to determine surface roughness values for each direction sector, and a 10-by-10-kilometer area to determine the mid-day albedo and daytime Bowen Ratio. AERSURFACE will be run for month-specific surface characterization. The AERMET (Version 13350) pre-processor will then be used to prepare meteorological data for use in AERMOD. Output from AERSURFACE will be input to AERMET along with surface and upper air meteorological observation data. Guidance provided in the most recent AERMOD Implementation Guide (USEPA 2009) will be followed.

Surface wind data sets will consist of automatic surface observing system (ASOS) 1-minute wind data from the Lake Charles Regional airport. These data sets will be processed using the AERMINUTE data pre-processor program for subsequent use in Stage 2 of AERMET data processing.

4.4 RECEPTORS

Impacts will be analyzed at receptors placed along and beyond the fence line of the Project site. Guidance provided by the USEPA describing locations considered as ambient air will be followed. In general, the guidance states that any property owned by the Project within a fenced in area (or area with public access controlled by other means) is not considered ambient air; locations outside of fenced-in locations owned by the Project are considered ambient air, including over-water locations.

The initial receptor grid will be established using a Cartesian grid at the following intervals:

- Along fence line: 100-meter spacing.
- Fence line to 1 kilometer beyond fence line: 100-meter spacing.
- From 1 kilometer to 5 kilometers beyond fence line: 500-meter spacing.
- From 5 kilometers to 10 kilometers beyond fence line: 1-kilometer spacing.

If the initial modeling indicates ambient concentrations remain above the applicable SIL beyond 10 kilometers, the receptor grid will be extended to determine the full extent of the area of influence, not to exceed 50 kilometers (the geographic/dispersion limit of the model) from the Project fence line. SILs are defined by the USEPA as ambient concentrations of air pollutants above which the potential for a significant air quality impact is deemed possible. It follows that if modeled ambient concentrations of air pollutants are below a SIL, a significant air quality impact is not likely and no further modeling is required. If the maximum concentration occurs beyond 1 kilometer of the fence line, then an additional receptor grid with 100-meter spacing will be set up, centered on the receptor with the maximum impact to ensure the maximum impact is identified. Receptor elevations will be determined using AERMAP as discussed in Section 4.2.

The Mossville environmental justice community is located approximately 7 miles (11.3 kilometers) north of the Project site. The initial receptor grid outlined above will extend to 6.2

miles (10 kilometers) from the Project site. As noted in the preceding paragraph, if modeled impacts are above the applicable SIL at 6.2 miles (10 kilometers), the receptor grid will be extended so that ambient concentrations at receptors beyond 6.2 miles (10 kilometers), including the Mossville area, will be determined. Discrete (i.e., individual) receptors will be placed in the Mossville community to supplement the extended grid.

4.5 ESTIMATING NO_2 MODELED CONCENTRATIONS

Emissions from a combustion source are primarily composed of two compounds, nitrogen oxide (NO) and nitrogen dioxide (NO_2), that are added together to determine total NO_X. The primary component of NO_X in the stack is NO. However, the NAAQS for this class of compounds has been established for NO_2 since NO_2 is the photochemically reactive form of NO_X that participates in ozone formation.

The USEPA has established a three tier procedure for determining the quantity of NOx emitted from an emission source that ultimately converts to NO_2 as described in the USEPA Guideline on Air Quality Models. Although the procedure was originally established to address the former annual NO_2 NAAQS, the procedures are still considered technically appropriate for the short-term NO_2 NAAQS. The tiered approach is intended to act as a screening procedure, with Tier 1 providing the most conservative result. Tiers 2 and 3 are used if unacceptable results are realized from Tier 1.

In Tier 1, full conversion of NO_X to NO_2 is assumed in modeling. If the NAAQS for NO_2 is exceeded, then the refined technique found in Tier 2 is applied.

In Tier 2, the Tier 1 1-hour modeled results will be multiplied by a NO_2 to NO_X ambient equilibrium ratio of 0.8 as recommended by the LDEQ. As in Tier 1, if the modeled results show an exceedance of the NAAQS, Tier 3 is applied.

Tier 3 consists of applying one of two non-default techniques available in the latest version of AERMOD that account for the atmospheric chemistry relationship between the conversion of NO_X to NO_2 and ambient ozone concentrations. Use of Tier 3 requires review by the USEPA as well as the LDEQ. Both techniques are fundamentally based on the limitation of NO_X to NO_2 conversion by the ambient ozone concentration and in-stack NO_X conditions. The Ozone Limiting Method (OLM) procedure applies a series of steps to determine the amount of NO_X that ultimately converts to NO_2 based on the amount of ozone present in the atmosphere. Conversion of NO_X to NO_2 is "limited" if the modeled NO_X concentration is greater than the ambient ozone concentration. The second ozone method under Tier 3 is the Plume Volume Molar Ratio Method (PVMRM). The PVMRM method takes into account more detailed information regarding the atmospheric chemistry processes in the plume resulting in conversion of NO_X to NO_2. For both Tier 3 methods, a value for the ambient ozone concentration is required.

For this project, the modeling analysis will apply each tier when modeling NO_2 in sequence, as necessary to demonstrate compliance with the NO_2 NAAQS. If Tier 3 becomes

necessary, Magnolia will provide a supplement to this protocol to address data assumptions for the Tier 3 methodology. Proposed data to be discussed would include:

- Background ozone concentration;
- NO_2 to NO_X equilibrium ratio; and
- In-stack NO_2 to NO_X ratio for each modeled source emitting NO_X;

5 CLASS I MODELING METHODOLOGY AND ADDITIONAL IMPACT ANALYSIS

5.1 CLASS I

In addition to the comparison against ambient air quality standards for Class II modeling, an analysis of air quality impacts to Class I areas must also be assessed. Class I areas include locations under the jurisdiction of the United States Fish and Wildlife Service, United States Forest Service, and the National Park Service. The Class I designation has also been given to specific Native American lands that have been determined to require special treatment for air quality purposes. The closest Class I area to the Project site is the Breton National Wildlife Refuge (approximately 420 kilometers to the east-southeast off the coast of Louisiana/Mississippi). Typically, distances greater than 300 kilometers between an emission source and a Class I area precludes the need for further Class I air quality analyses. For a source to Class I distance greater than 400 kilometers, the FLAG screening test (Q/d) is not required. Therefore, due to the separation distance of greater than 400 kilometers, a Class I air quality screening analysis and refined impact assessment will not be required.

5.2 ADDITIONAL IMPACT ANALYSIS

Magnolia will prepare an additional impact analysis following the guidelines in Chapter D of the USEPA New Source Review Workshop Manual (USEPA 1990) to address growth and associated ambient air quality impacts, soils and vegetation impacts and visibility impairment. The growth analysis will consider the Project's potential impact and emissions associated with growth of industrial, commercial and residential sectors as a result of the Project. The soils and vegetation assessment will consider the modeled ambient concentration resulting from the Project in comparison to secondary NAAQS that have been established for the purpose of protecting plants and animals from harm due to air quality. The visibility impairment analysis will consist of a determination of the visual quality in the area and an initial screening-level assessment of the possibility of visibility impairment. If necessary, a more in-depth analysis following procedures in the USEPA's Workbook for Plume Visual Impact Screening and Analysis (USEPA 1992) would be performed if initial screening indicated a potential impact.

6 REPORTING OF RESULTS

The air quality modeling analysis will be documented in a report that includes a summary narrative and a tabulation of the model results to demonstrate compliance with the applicable ambient air quality standards and other thresholds. The report will include the following elements:

- Detailed description of the proposed activity and emission sources with specific parameters used in the analysis including emission rates, stack heights, stack diameters, temperatures, exit velocities, and nearby building dimensions;
- Facility plot plan showing the location of emission sources, facility buildings, fence line corners, and terrain characteristics;
- Map (i.e., USGS with 1:24,000 scale) showing the facility location and receptors used in the analysis;
- Description of the model(s) selected and rationale for selection;
- Description of the site topography and receptor grids used in the analysis;
- Description of meteorological data;
- Technical support documentation for any assumptions made in the modeling analysis which deviate from the stated guidance; and
- Summary of model predictions showing comparison to applicable ambient air quality standards.

Digital copies of relevant model files will be included with the report, such as, but not limited to:

- Facility plot plan (in geo-referenced digital format);
- Meteorological files (.SFC and .PFL);
- Terrain files (USGS DEM files);
- Geo-referenced maps;
- Files related to BPIP-PRIME runs; and
- AERMOD model generated input and output files.

Reports and applicable digital files will be submitted to the LDEQ as part of the permit-to-construct application.

7 REFERENCES

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———. 2013b. Circuit Court Decision on PM2.5 Significant Impact Levels and Significant Monitoring Concentration, Questions and Answers. March 4, 2013. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards.

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Appendix A
Preliminary Operational Emission Estimates

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Table A1
Preliminary Potential Operation Emissions (tons per year) – Magnolia LNG

Emission Source	NO_X	CO	SO2	PM10	PM2.5	VOC	HAPs	CO2e
Gas Turbines (8)	1,016	639	32	74	74	45	11	1,318,269
Thermal Oxidizers (4)	18	30	0.2	3	3	2	1	42,725
Auxiliary Boiler (4)	83	139	1	13	13	9	4	198,469
Emergency Generator (1)	1.5	3	0	0.02	0.02	0.7	0.13	249
Emergency Fire Water Pump (1)	0.7	1.5	0	0.01	0.01	0.4	0.06	125
Total	1,119	813	33	90	90	57	16	1,559,837

Table A2
Emissions for GE PGT25+G4/DLE
Magnolia LNG

Parameter		Units	Value
Fuel Lower Heating Value (LHV)[1]		Btu/scf	935.1
Fuel Higher Heating Value (HHV) [1]		Btu/scf	1036.4

Parameter	Units	Turbine 1	Number of Turbines	Total for Eight Turbines
Hourly Fuel Flow (LHV) - Maximum[2]	MMBtu/hr	287.30	8	2,298
Hourly Fuel Flow (LHV) - Average[3]	MMBtu/hr	287.30	8	2,298
Hourly Fuel Flow (HHV) - Maximum[4]	MMBtu/hr	318.42	8	2,547
Hourly Fuel Flow (HHV) - Average[4]	MMBtu/hr	318.42	8	2,547
Annual Operation @ 100% Load	hr/yr	8760	8	70,080
Maximum Annual Fuel Flow (LHV)[5]	MMBtu/yr	2,516,748	8	20,133,984
Maximum Annual Fuel Flow (HHV)[6]	MMBtu/yr	2,789,389	8	22,315,112
Maximum Annual Fuel Flow (volume)[6]	MMscf/yr	2,690	8	21,520

				Each Turbine		Eight Turbines	
Pollutant Type	Pollutant	LHV Emission Factor (lb/MMBtu)	HHV Emission Factor[7,8,9] (lb/MMBtu)	Maximum Hourly Emission Rate (lb/hr)	Maximum Annual Emissions (tpy)	Annual Emissions (tpy)	
Criteria	NO_X			29.00	127.02	1016.2	
	CO			18.24	79.89	639.1	
	VOC			1.28	5.61	44.9	
	PM	-	0.0066	2.10	9.20	73.6	
	PM_{10}	-	0.0066	2.10	9.20	73.6	
	$PM_{2.5}$	-	0.0066	2.10	9.20	73.6	
	SO_2	-	0.0028	0.90	3.93	31.5	
HAPs	Acetaldehyde	-	0.000040	0.013	0.056	0.4	
	Acrolein	-	0.0000064	0.002	0.009	0.1	
	Benzene	-	0.000012	0.004	0.017	0.1	
	Ethylbenzene	-	0.000032	0.010	0.045	0.4	
	Formaldehyde	-	0.00071	0.226	0.990	7.9	
	Toluene	-	0.00013	0.041	0.181	1.5	
	Xylenes	-	0.000064	0.020	0.089	0.7	
	Total HAPs	-	**-**	**0.3166**	**1.387**	**11.095**	
Greenhouse Gas	CO_2			37218	163,015	1304118.7	
	N_2O	-	0.003	0.96	4.18	33.5	CO_2e Multiplier
	CH_4	0.028	0.0255	5.13	22.46	179.7	
Greenhouse Gas (CO_2e)	CO_2	-	-	37,218	163,015	1,304,119	1
	N_2O	-	-	296	1,297	10,377	310
	CH_4	-	-	108	472	3,773	21
	Total GHGs	-	**-**	**37,622**	**164,784**	**1,318,269**	

Notes:
1. Data from GE PGT25+G4 DLE Expected Emissions.xlsx sheet (based on Fuel Number 800-41 Magnolia).
2. Data from GE PGT25+G4 Turbine Specification Sheets. Fuel flow based on inlet temperature chilled to 15.0 ^{o}C dry bulb.
3. Inlet cooling to be used to maintain inlet temperature, therefore little variation between hourly maximum and annual average.
4. Calculated from hourly fuel flow (LHV basis) and ratio of HHV to LHV.
5. Maximum annual fuel flow for each turbine calculated by multiplying maximum hourly fuel (LHV) by annual operation @ 100% load.

Table A2
Emissions for GE PGT25+G4/DLE
Magnolia LNG

6. Calculated from maximum annual fuel flow (LHV).
7. NO_X, CO, VOC, and CH_4 emission factors from GE PGT25+G4 Turbine Specification Sheets.
8. CO_2 emission factor from GE PGT25+G4 DLE Expected Emissions.xlsx.
9. Emissions factors from United States Environmental Protection Agency (EPA). 2000. AP 42 Fifth Edition, Volume I - Section 3.1 - Stationary Gas Turbines. PM emission factors based on total PM (condensable and filterable fraction). PM_{10} and $PM_{2.5}$ emission factors assumed equal to total PM emission factor (condensable and filterable fractions). SO_2 emission factor based on sulfur content of 0.003%.

Table A3
Emissions for Emergency Generator Engine
Magnolia LNG

Parameter		Value	Units
Power Rating		1000	kW
		1341	
Engine Fuel Flow Rate (HHV)[1]		5,534	Btu/hp-hr
		7.42	MMBtu/hr
Higher Heating Value (HHV)[2]		1036.4	Btu/scf
Maximum Yearly Operation		500	hr/yr

Pollutant Type	Pollutant	HHV Emission Factor[3] (lb/MMBtu)	Emission Factor[4] (g/hp-hr)	Maximum Hourly Emission Rate[5] (lb/hr)	Annual Emissions (tpy)	
Criteria	NO_X	-	2.0	5.91	1.5	
	CO	-	4.0	11.8	3.0	
	VOC	-	1.0	2.96	0.7	
	PM	0.00999	-	0.073	0.018	
	PM_{10}	0.00999	-	0.073	0.018	
	$PM_{2.5}$	0.00999	-	0.073	0.018	
	SO_2	0.000588	-	0.0043	0.0011	
HAPs	Acetaldehyde	0.00836	-	0.061	0.015	
	Acrolein	0.00514	-	0.038	0.009	
	Benzene	0.000440	-	0.0032	0.0008	
	Ethylbenzene	0.0000397	-	0.00029	0.000072	
	Hexane	0.00111	-	0.008	0.0020	
	Formaldehyde	0.0528	-	0.39	0.10	
	Toluene	0.000408	-	0.0030	0.00074	
	Xylenes	0.000184	-	0.0013	0.00034	
	Total HAPs	**-**	**-**	**0.50**	**0.13**	
Greenhouse Gas	CO_2	110	-	803	201	CO_2e
	CH_4	1.25	-	9	2.3	Multiplier
Greenhouse Gas (CO_2e)	CO_2	-	**-**	803	201	1
	CH_4	-	**-**	192	48	21
	Total GHGs	**-**	**-**	**995**	**249**	

Notes:

1. Estimated based on typical unit.
2. Based on HHV used by GE for gas turbines for project.
3. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 3.2 - Natural Gas-fired Reciprocating Engines. July. Emission factors for 4-stroke lean burn engines. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensable and filterable fractions.
4. Applicable emission limits for spark-ignition emergency generators in NSPS Subpart JJJJ.
5. Emission rates, except NO_X, CO, and VOC, calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and dividing by listed HHV.

Table A4
Emissions for Fire Water Pump Engine
Magnolia LNG

Parameter		Value	Units
Power Rating		500	kW
		670	
Engine Fuel Flow Rate (HHV)[1]		2,767	Btu/hp-hr
		1.85	MMBtu/hr
Higher Heating Value (HHV)[2]		1036.4	Btu/scf
Maximum Yearly Operation		500	hr/yr

Pollutant Type	Pollutant	HHV Emission Factor[3] (lb/MMBtu)	Emission Factor[4] (g/hp-hr)	Maximum Hourly Emission Rate[5] (lb/hr)	Annual Emissions (tpy)	
Criteria	NO_X	-	2.0	2.95	0.7	
	CO	-	4.0	5.9	1.5	
	VOC	-	1.0	1.48	0.4	
	PM	0.00999	-	0.018	0.005	
	PM_{10}	0.00999	-	0.018	0.005	
	$PM_{2.5}$	0.00999	-	0.018	0.005	
	SO_2	0.000588	-	0.0011	0.0003	
HAPs	Acetaldehyde	0.00836	-	0.015	0.004	
	Acrolein	0.00514	-	0.009	0.002	
	Benzene	0.000440	-	0.0008	0.0002	
	Ethylbenzene	0.0000397	-	0.00007	0.000018	
	Hexane	0.00111	-	0.002	0.0005	
	Formaldehyde	0.0528	-	0.10	0.02	
	Toluene	0.000408	-	0.0007	0.00019	
	Xylenes	0.000184	-	0.0003	0.00008	
	Total HAPs	**-**	**-**	**0.12**	**0.03**	
Greenhouse Gas	CO_2	110	-	201	50	CO_2e
	CH_4	1.25	-	2	0.6	Multiplier
Greenhouse Gas (CO_2e)	CO_2	-	**-**	201	50	1
	CH_4	-	**-**	48	12	21
	Total GHGs	**-**	**-**	**249**	**62**	

Notes:
1. Estimate.
2. Based on HHV used by GE for gas turbines for project.
3. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 3.2 - Natural Gas-fired Reciprocating Engines. July. Emission factors for 4-stroke lean burn engines. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensible and filterable fractions.
4. Applicable emission limits for spark-ignition emergency generators in NSPS Subpart JJJJ.
5. Emission rates, except NO_X, CO, and VOC, calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and dividing by listed HHV.

Table A5
Emissions for Thermal Oxidizer
Magnolia LNG

Parameter		Value	Units
Fuel Flow Rate (HHV)[1]		20.23	MMBtu/hr
Higher Heating Value (HHV)[2]		1043	Btu/scf
Maximum Yearly Operation		8760	hr/yr

Pollutant Type	Pollutant	AP42 Emission Factor[3] (lb/MMscf)	HHV Emission Factor[3] (lb/MMBtu)	Maximum Hourly Emission Rate (each)[4] (lb/hr)	Annual Emissions for Four Units (tpy)	
Criteria	NO_X	50.00	0.0501	1.01	17.8	
	CO	84.000	0.0842	1.70	29.8	
	VOC	5.5000	0.0055	0.11	2.0	
	PM	7.6	0.0076	0.15	2.7	
	PM_{10}	7.6	0.0076	0.15	2.7	
	$PM_{2.5}$	7.6	0.0076	0.15	2.7	
	SO_2	0.600000	0.0006	0.01	0.2	
HAPs	2-methylnapthalene	0.000024	0.000000	0.0000	0.000	
	Anthracene	0.000002	0.000000	0.0000	0.000	
	Benzene	0.0021	0.000002	0.0083	0.145	
	Dichlorobenzene	0.0012	0.000001	0.0000	0.000	
	Hexane	1.8000	0.001804	0.0365	0.640	
	Formaldehyde	0.0750	0.000075	0.0015	0.027	
	Napthalene	0.0006	0.000001	0.0000	0.000	
	Toluene	0.0034	0.000003	0.0244	0.427	
	Xylene	0.0000	0.000000	0.0280	0.490	
	Total HAPs	**-**		**0.07**	**1.24**	
Greenhouse Gas	CO_2	120000	120.2999	2433.67	42,637.840	CO_2e
	N2O	0.64	0.0006	0.01	0.227	
	CH_4	2.30	0.0023	0.05	0.817	Multiplier
Greenhouse Gas (CO_2e)	CO_2	-		2,434	42,638	1
	N2O			4	70	310
	CH_4	-		1	17	21
	Total GHGs	**-**		**2,439**	**42,725**	

Notes:
1. Estimate from preliminary design data from Magnolia LNG.
2. Based on HHV for feed gas for project used for aux boiler and thermal oxidizer spec.
3. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 1.4. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensable and filterable fractions.
4. Emission rates calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and dividing by listed HHV. Emission of benzene, toluene and xylene include contribution from pilot fuel and waste gas stream.

Table A6: Estimated BTEX Destruction Efficiency

	Aux. Boiler Fuel			Thermal Oxidiser		
Destruction Efficiency		**99.99%**			**99.00%**	
	INLET	**OUTLET**		**INLET**	**OUTLET**	
	Mass Flow (kg/hr)	**Mass Flow, t/yr**		**Mass Flow (kg/hr)**	**Mass Flow, t/yr**	
CO2	0.005			10502.0366		
Nitrogen	0.014			0.0000		
Methane	73.511			5.4082		
Ethane	75.195			0.5032		
Propane	79.130			0.1054		
i-Butane	67.528			0.0000		
n-Butane	103.827			0.0000		
i-Pentane	199.821			0.0000		
n-Pentane	347.825			0.0000		
n-Hexane	534.789		lb/hr	0.0000		lb/hr
Benzene	137.574	0.121	0.030329	0.3735	0.033	0.008234
Cyclohexane	50.163	0.044	0.011059	0.0000		
n-Heptane	227.860			0.0000		
Toluene	41.926	0.037	0.009243	1.1015	0.096	0.024283
n-Octane	25.997			0.0000		
p-Xylene	16.108	0.014	0.003551	1.2691	0.111	0.027979
E-Benzene	16.108	0.014	0.003551	0.0000		
H2S	0.001			1.9553		
Ammonia	0.000			0.0000		
H2O	0.000			0.0000		
Total	**1997.382**	**0.229**		**10512.753**	**0.240**	
For 4 Trains		0.92			0.96	
Total MLNG Plant		**1.88**	**t/yr**			

Table A7
Emissions for Auxiliary Boiler
High BTU Feed Gas and Waste Gas
Magnolia LNG

Parameter		Value	Units
Fuel Flow Rate [1]		92,130	ft3/hr
		96.00	MMBtu/hr
Higher Heating Value (HHV)[1]		1043	Btu/scf
Maximum Yearly Operation		8760	hr/yr

Pollutant Type	Pollutant	AP42 Emission Factor[3] (lb/MMscf)	HHV Emission Factor[3] (lb/MMscf)	Maximum Hourly Emission Rate[4] (lb/hr)	Annual Emissions (tpy)	Annual Emissions Four Units (tpy)	
Criteria	NO_X	50	51.1275	4.71	20.6	82.53	
	CO	84	85.8941	7.91	34.7	138.64	
	VOC	5.5	5.6240	0.52	2.3	9.08	
	PM	7.6	7.7714	0.72	3.136	12.54	
	PM_{10}	7.6	7.7714	0.72	3.136	12.54	
	$PM_{2.5}$	7.6	7.7714	0.72	3.136	12.54	
	SO_2	0.60	0.6135	0.06	0.2476	0.99	
HAPs	2-methylnapthalene	0.000024	0.0000	0.00000	0.000	0.00	
	Anthracene	0.000002	0.0000	0.00000	0.000	0.00	
	Benzene	0.0021	0.0021	0.03053	0.1337	0.53	
	Cyclohexane	0.0000	0.0000	0.01106	0.0484	0.19	
	Dichlorobenzene	0.0012	0.0012	0.00011	0.000495	0.00	
	Ethylbenzene	0.0000	0.0000	0.00355	0.0156	0.06	
	Hexane	1.8000	1.8406	0.16957	0.7427	2.97	
	Formaldehyde	0.0750	0.0767	0.00707	0.03	0.12	
	Napthalene	0.0006	0.0006	0.00006	0.00	0.00	
	Toluene	0.0034	0.0035	0.00032	0.00140	0.01	
	Xylene	0.0000	0.0000	0.00355	0.0156	0.06	
	Total HAPs			**0.22**	**0.99**	3.96	
Greenhouse Gas	CO_2	120000	122705.8824	11304.89	49,515	198,062	
	N_2O	0.64	0.6544	0.06	0	1	CO_2e Multiplier
	CH_4	2.30	2.3519	0.22	1	4	
Greenhouse Gas (CO_2e)	CO_2			11,305	49,515	198,062	1
	N_2O			19	82	327	310
	CH_4			5	20	80	21
	Total GHGs			**11,328**	**49,617**	198,469	

Notes:

1. From Babcock & Wilcox P55-6356_BW_Budget_R01.pdf Oct 15 2013.

2. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 1.4. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensable and filterable fractions.

3. Emission rates calculated from EPA emission factors and fuel flow. Since emission factors are based on heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by ratio of actual fuel heat value divided by 1020.

4. Emission rates calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and

Table A7
Emissions for Auxiliary Boiler
High BTU Feed Gas and Waste Gas
Magnolia LNG

dividing by listed HHV. Emission of benzene, toluene and xylene include contribution from pilot fuel and waste gas stream.

Table A8
Natural Gas Composition Data
Magnolia LNG

Component	Molar (Volume) Fraction[1] (wgt %)	Component Molecular Weight (lb/lbmole)	Weighted Sum Flash Gas Molecular Weight (lb/lbmole)	Weight Fraction (wgt %)
Nitrogen	1.014	28.01	0.284	1.692
Carbon Dioxide	0.01	44.01	0.003	0.02
Methane	95.60	16.04	15.34	91.3
Ethane	2.56	30.07	0.770	4.58
Propane	0.32	44.10	0.143	0.852
I-Butane	0.091	58.12	0.053	0.316
N-Butane	0.091	58.12	0.053	0.316
I-Pentane	0.0811	72.15	0.059	0.348
N-Pentane	0.0811	72.15	0.059	0.348
Hexanes	0.035	95.96	0.033	0.197
Total	**99.9**	**-**	**16.79**	**100.0**

HAP Component	Molar (Volume) Fraction[2] (wgt %)	Component Molecular Weight (lb/lbmole)	Weighted Sum Flash Gas Molecular Weight (lb/lbmole)	Weight Fraction (wgt %)
Benzene	0.00310	78.114	0.00242	0.0144
Ethylbenzene	0.00002	106.167	0.00002	0.000109
n-Hexane	0.00100	86.177	0.00086	0.0051
Toluene	0.00100	92.141	0.00092	0.00549
Xylenes	0.00100	106.167	0.00106	0.00632
Total HAPs	**0.0061**	-	-	**0.0315**

Component	Weight Fraction in Natural Gas (wgt %)	Weight Fraction in TOC (wgt %)
TOC	98.3	100
Methane	91.3	92.9
VOC	2.38	2.42
Benzene	0.0144	0.0147
Ethylbenzene	0.000109	0.000111
n-Hexane	0.005	0.005
Toluene	0.00549	0.00558
Xylenes	0.00632	0.00643
Total HAPs	0.0315	0.0320

Table A8
Natural Gas Composition Data
Magnolia LNG

Notes:

1. Based on Fuel Number 800-41 Magnolia provided by GE for PGT25+G4 DLE emissions.

2. Component split based on GRI GLY-Calc V4.0 lumped C6+ gas analysis multipliers for the Natural Gas Transmission Industry Segment.

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Appendix 9.C.2

Marine and Stationary Sources Air Quality Modeling Protocol

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March 21, 2014

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Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Magnolia LNG, LLC
PF13-9-000
Marine and Stationary Sources Air Modeling Protocol

Dear Secretary Bose:

Attached please find Magnolia LNG, LLC's ("Magnolia LNG") Marine and Stationary Sources Air Modeling Protocol ("Air Modeling Protocol"). The Air Modeling Protocol was prepared by Ecology and Environment, Inc., Magnolia LNG's environmental consultant, and describes the methods, pre- and post-processing programs, and model that will be used to determine the air quality impacts for the Magnolia LNG Project proposed in the docket number referenced above.

Any questions regarding this correspondence may be directed to the undersigned at 202.778.9178 or sandra.safro@klgates.com.

Best regards,

/s/ Sandra E. Safro
Sandra E. Safro
Counsel for Magnolia LNG, LLC

Enclosures

cc: Janine Cefalu, FERC

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MAGNOLIA LNG PROJECT

Marine and Stationary Sources Air Quality Modeling Protocol

March 18, 2014

Submitted to:

Federal Energy Regulatory Commission

Submitted by:

MAGNOLIA LNG

Magnolia LNG, LLC
1001 McKinney, Suite 400
Houston, TX 77002

Prepared by:

ecology and environment, inc.
Global Environmental Specialists

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APPENDIX

A Preliminary Operational Emission Estimates

ACRONYMS AND ABBREVIATIONS

BACT	Best Available Control Technology
BPIP-PRIME	Building Profile Input Program with Prime
BTEX	benzene, toluene, ethylbenzene, and xylene
Btu	British thermal unit
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2e	carbon dioxide equivalent
DEM	digital elevation models
DFDE	dual fuel diesel electric
DLE	dry-low emissions
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
hp	horsepower
IMO	International Maritime Organization
KMLP	Kinder Morgan Louisiana Pipeline
LAC	Louisiana Administrative Code
LDEQ	Louisiana Department of Environmental Quality
LNG	liquefied natural gas
m^3	cubic meter(s)
Magnolia	Magnolia LNG, LLC
MARPOL	International Convention for the Prevention of Pollution from Ships
mtpa	million (metric) tonnes per annum
NAAQS	National Ambient Air Quality Standards
NAECA	North American Emission Control Area
NEPA	National Environmental Policy Act
NNSR	nonattainment new source review
NO_2	nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration

NO_X	nitrogen oxide
NSR	New Source Review
OSMR®	Optimized Single Mixed Refrigerant
PM_{10}	particulate matter equal to or less than 10 micrometers aerodynamic diameter
$PM_{2.5}$	particulate matter equal to or less than 2.5 micrometers aerodynamic diameter
Port	Lake Charles Harbor & Terminal District
Project	Magnolia LNG Project
PSD	Prevention of Significant Deterioration
PTE	potential to emit
PVMRM	plume volume molar ratio method
SIL	significant impact level
SMC	significant monitoring concentration
TAP	toxic air pollutant
tpy	tons per year
USCG	United States Coast Guard
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compounds
WSA	Waterway Suitability Assessment

1 INTRODUCTION

1.1 OBJECTIVE

Magnolia LNG, LLC (Magnolia) has prepared this protocol to describe the methods, pre- and post-processing programs, and model to be used to determine the proposed Magnolia LNG Project's air quality impacts. Although marine vessel sources are not regulated by federal or state air permitting regulations and associated ambient impact analysis requirements, the Federal Energy Regulatory Commission (FERC) has requested the inclusion of marine vessel emission sources in an air dispersion modeling analysis for National Environmental Policy Act (NEPA) purposes.

This protocol includes marine sources in the emission inventory to be modeled, but otherwise mirrors the stationary source protocol submitted to the Louisiana Department of Environmental Quality (LDEQ) in terms of methodology, stationary source input data to be used, model to be used, receptor grid, terrain data and meteorological data. Model results will be compared to significant impact levels (SILs), and, for impacts above applicable SILs, used to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) Increment levels. The protocol is based on the current United States Environmental Protection Agency's (USEPA's) Guideline on Air Quality Models (USEPA 2005), the USEPA's New Source Review Workshop Manual (1990), various recent USEPA memoranda regarding modeling procedures for short term standards analysis, and the LDEQ's Air Quality Modeling Procedures (the latter as updated by discussions with LDEQ) (LDEQ 2006).

1.2 PROJECT DESCRIPTION

Magnolia is proposing to develop a natural gas liquefaction facility in Lake Charles, Calcasieu Parish, Louisiana, on a tract of land that was previously used by the United States Army Corps of Engineers (USACE) as a confined disposal facility (CDF) to dispose dredge materials of the adjacent Industrial Canal. Calcasieu Parish is located in the Southern Louisiana-Southeast Texas Interstate Air Quality Control Region. Calcasieu Parish is designated as attainment/unclassifiable for all criteria pollutants.

The Magnolia LNG Project (referred to herein as the Project) facility would be capable of producing a nominal capacity of approximately 8.0 million (metric) tonnes per annum (mtpa) of liquefied natural gas (LNG). Magnolia would use its highly efficient and patented Optimized Single Mixed Refrigerant (OSMR®) technology to produce LNG. The Project would receive natural gas via an existing pipeline that passes beneath the Project site near the southern boundary. Associated with the Project, Kinder Morgan Louisiana Pipeline (KMLP) would develop a compressor station in Eunice Louisiana, approximately 52 miles from the Project site. Permitting and any modeling required for the KMLP Eunice compressor station would be undertaken directly by KMLP and filed separately with the FERC.

The natural gas would be treated, liquefied, and stored on site in two full containment LNG storage tanks with a net pumpable capacity of approximately 160,000 cubic meters (m^3) each. At full plant capacity, the Project would consist of four LNG trains each with a nominal capacity of 2.0 mtpa of LNG (total nominal capacity of approximately 8.0 mtpa). The LNG would be loaded onto LNG carriers for export overseas; LNG carriers and barges for domestic marine distribution and the possibility of LNG bunkering; and LNG trucks for road distribution to LNG refueling stations in Louisiana and the surrounding states.

1.3 FACILITY LOCATION AND PRELIMINARY SITE LAYOUT

The Project would be located on the Industrial Canal South Shore Port of Lake Charles Tract 475, an approximately 115-acre parcel of land in Calcasieu Parish, south of Lake Charles, available through a long-term lease with the Lake Charles Harbor & Terminal District (the Port). The Industrial Canal is located off the main Calcasieu River Ship Channel. The Project would be located in an area zoned for heavy industrial use and would be consistent with other industrial facilities along the shoreline. The coordinates of the proposed Project site are as follows: Latitude: 30° 06′ 20.30″ N; Longitude: 93° 17′54.00″ W. Figure 1 is a general location map of the Project.

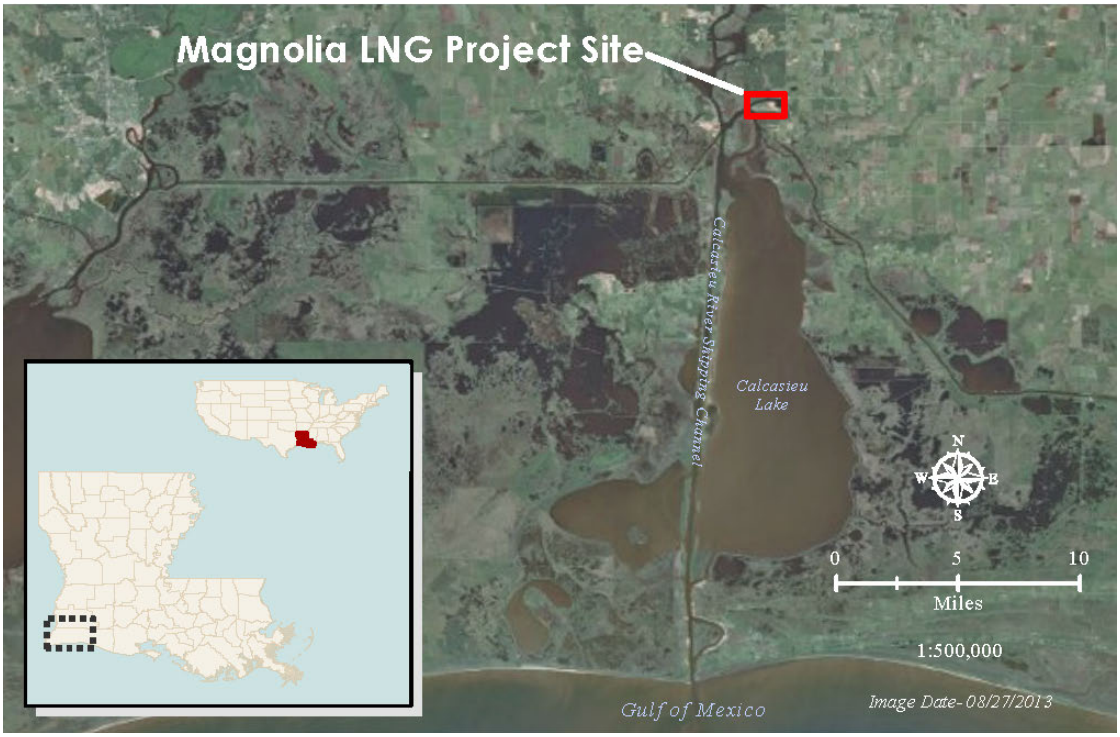


Figure 1 General Location Map of the Magnolia LNG Project

On March 6, 2013, Magnolia signed an exclusive and binding four-year Real Estate Lease Option Agreement (Option Agreement) with the Port for the Project site. The Option Agreement includes a clause for a 30-year-term ground lease option with the right to extend the lease term for four periods of 10 years each, for a total of 70 years. The expected operational life of the Project is a minimum of 30 years. Figure 2 shows the boundary of the lease area.

Magnolia has prepared a preliminary layout of equipment on the leased area. Figure 3 shows the location of the emission sources to be modeled for the Project analysis and air permit application. In addition to the stationary sources illustrated on Figure 3, an LNG carrier is shown in the berth directly north of the LNG storage tanks. Note the orientation of the carrier with the bow pointed west and the exhaust stack located on the stern. This orientation will be used to model the LNG carrier. Tug boats accompanying the LNG carrier (not shown on Figure 3) would be released to return to port or other duties after the LNG carrier is moored at the loading dock. Although not illustrated on Figure 3, the LNG barge would be positioned in the same berth for loading of LNG onto barges. One tug would remain with the barge during loading and will be modeled as being positioned at the aft end of the barge.

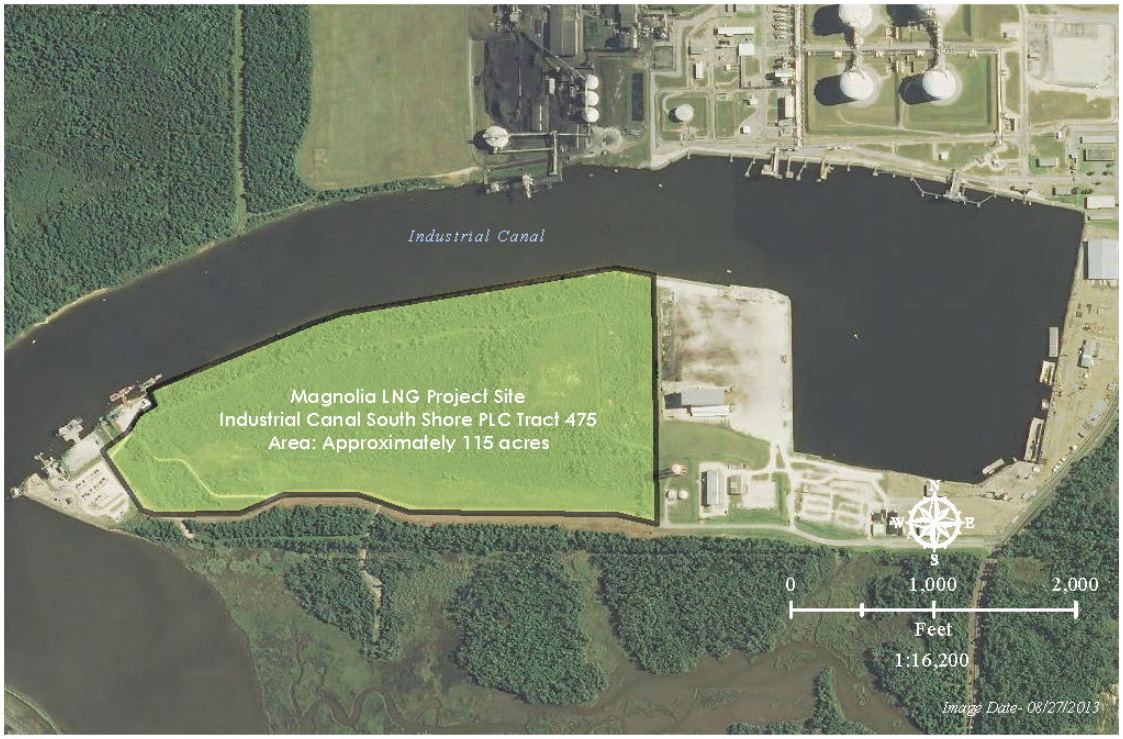


Figure 2 Project Site Boundary Map

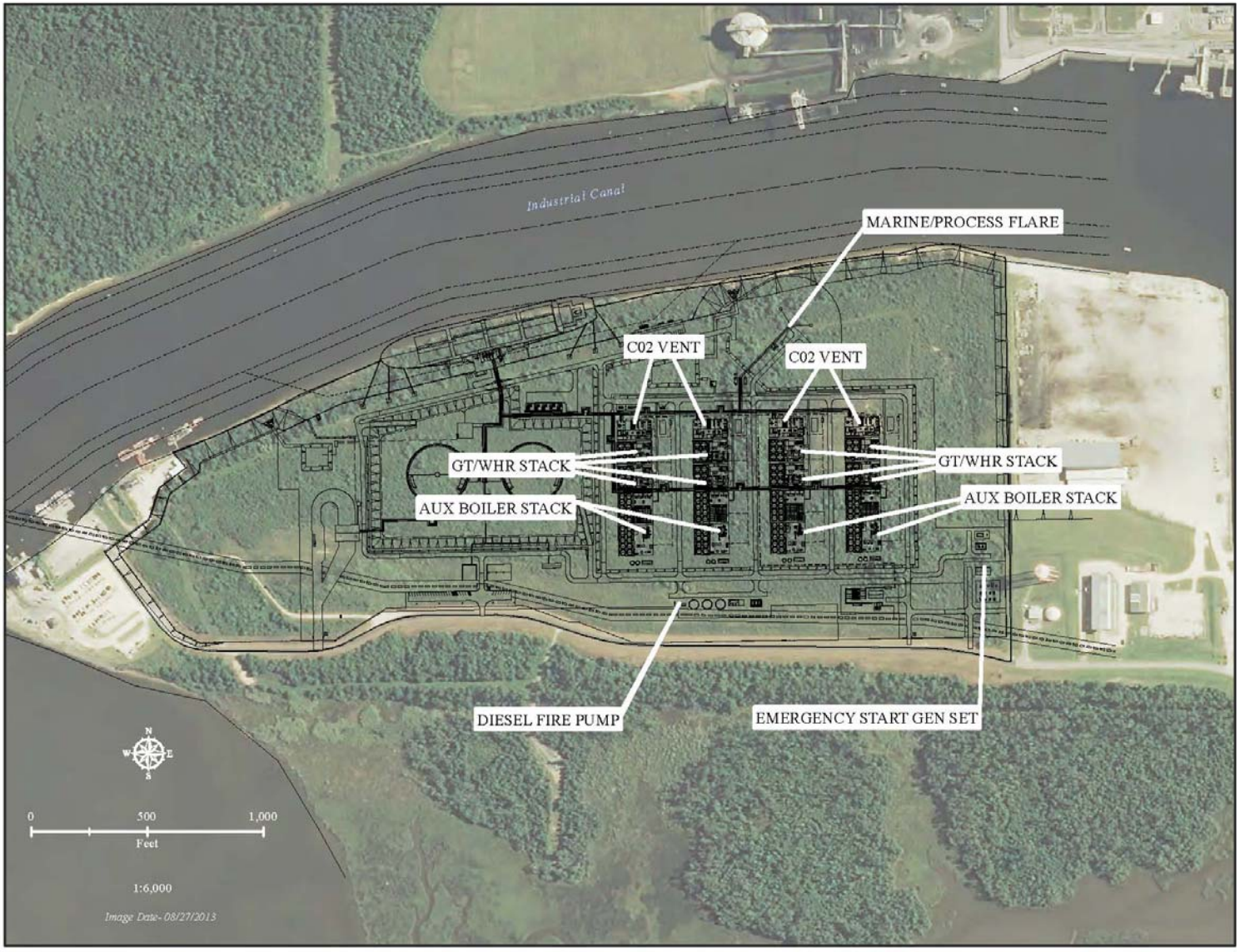


Figure 3 Preliminary Site Layout Showing Potential Emission Source Locations

1.4 SOURCE DESIGNATION

Initial potential to emit (PTE) estimates and Project location in an attainment area for all criteria pollutants indicate that a PSD modeling analysis will be required for the criteria pollutants nitrogen dioxide (NO_2), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter equal to or less than 10 micrometers aerodynamic diameter (PM_{10}), and particulate matter equal to or less than 2.5 micrometers aerodynamic diameter ($PM_{2.5}$). Emissions of greenhouse gas (GHG) also would be above PSD major source thresholds; however, GHGs are not currently subject to modeling requirements. Initial PTE for the Project is shown in Table 1. Note that emissions from mobile sources (the LNG carrier and the tug boats) associated with ship hoteling, docking, and undocking are not counted for PSD applicability purposes, and thus are listed after the PSD applicability determination total in Table 1. The initial estimate of marine source emissions included in draft Resource Report 9 has been revised with more detail and updated vessel activity information and is shown in Table 1. Emission calculation details are provided in Appendix A of this protocol.

Table 1 Preliminary Potential Operation Emissions (tons per year) for the Project

Emission Source	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC	HAPs	CO_2e
Gas Turbines (8)	1,016	639	32	74	74	45	11	1,318,269
Thermal Oxidizers (4)	18	30	0.2	3	3	2	1	42,725
Auxiliary Boiler (4)	83	139	1	13	13	9	4	198,469
Emergency Generator	1.5	3.0	0.0	0.02	0.02	0.7	0.13	249
Emergency Fire Water Pump	0.7	1.5	0.0	0.01	0.01	0.4	0.06	125
Flares	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Project Total	**1,119**	**813**	**33**	**90**	**90**	**57**	**16**	**1,559,837**
PSD Threshold	**250**	**250**	**250**	**250**	**250**	**250**	**N/A**	**100,000**
Trigger PSD?	**YES**	**YES**	**NO**	**NO**	**NO**	**NO**	**N/A**	**YES**
Significant Emission Rate	**40**	**100**	**40**	**15**	**10**	**40**	**N/A**	**N/A**
PSD Modeling Required?	**YES**	**YES**	**NO**	**YES**	**YES**	**YES**	**N/A**	**N/A**
LNG Carrier Hoteling	**6.9**	**5.4**	**0.8**	**0.3**	**0.3**	**2.4**	**N/A**	**1,984**
LNG Carrier Maneuvering near/at Dock	**0.5**	**0.4**	**0.2**	**0.02**	**0.02**	**0.1**	**N/A**	**112**
Tug Boats maneuvering w/Carrier at Dock	**43**	**5.4**	**1.7**	**1.6**	**1.6**	**2.0**	**N/A**	**2,336**
Tug Boat w/Barge near/at Dock	**16**	**2.0**	**0.5**	**0.6**	**0.6**	**0.7**	**N/A**	**863**

Key:
CO = carbon monoxide.
CO_2e = carbon dioxide equivalent.
HAPs = hazardous air pollutants.
LNG = liquefied natural gas.
N/A = Not applicable.
NO_X = nitrogen oxide.
PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.
$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.
PSD = Prevention of Significant Deterioration.
SO_2 = sulfur dioxide.
TBD = To be determined.
VOC = volatile organic compound.

2 APPLICABLE PERMITTING REGULATIONS AND SHORT-TERM MODELING GUIDANCE

2.1 NEW SOURCE REVIEW

New Source Review (NSR) refers to the preconstruction permitting programs under Parts C and D of the Clean Air Act. NSR must be addressed before construction can begin on new major stationary sources or major modifications to existing major stationary sources. The PSD program is the NSR permitting program for stationary sources located in attainment areas (below the NAAQS) and unclassified areas (areas for which there is insufficient information to determine attainment status). For stationary sources located in nonattainment areas, the NSR permitting program is the nonattainment new source review (NNSR) program. Stationary emission source thresholds for nonattainment areas are lower than the stationary emission source thresholds for attainment areas. The Project location is unclassifiable/ attainment and, therefore, is compared to attainment area major stationary source NSR thresholds.

The major stationary source attainment area NSR thresholds are either 100 tons per year (tpy) or 250 tpy. The 100 tpy threshold applies only to 28 distinct stationary source categories listed in 40 Code of Federal Regulations (CFR) 52.21. The Project does not belong to any of the 28 stationary source categories; therefore, the applicable major stationary source threshold is 250 tpy per criteria pollutant and 100,000 tpy for carbon dioxide equivalent (CO_2e). Estimated stationary source operational emissions would be above 250 tpy for nitrogen oxide (NO_X) and CO and above 100,000 tpy for CO_2e (see Table 1); therefore, the Project is subject to major stationary source NSR attainment area (PSD) permitting.

Emissions from the marine sources (LNG carrier and tug boats) described in this protocol are not subject to inclusion in determining major stationary source status, since NSR only applies to stationary emission sources. It also should be noted that while the LNG carriers and tug boats are engaged in commerce with Magnolia, Magnolia does not control the operation of these vessels since they are owned and operated by separate entities and are subject to operation requirements imposed by the United States Coast Guard (USCG). These latter requirements are in the process of being developed and may result in somewhat different vessel operations during the docking and undocking process. As changes to vessel operations emerge as a result of these requirements, they will be accommodated in the modeling analysis.

2.2 SHORT-TERM NAAQS MODELING GUIDANCE

The USEPA has provided guidance for modeling methodology for the 1-hour NO_2 NAAQS in a series of memoranda (USEPA 2010a, 2011). The guidance provided in these memoranda describes procedures for processing and interpreting model results with regards to the statistical form of the 1-hour NO_2 NAAQS. The USEPA has also provided guidance for modeling to demonstrate compliance with the $PM_{2.5}$ NAAQS (USEPA 2010b). Magnolia will follow these procedures when modeling and processing model results.

3 MODELING METHODOLOGY

3.1 CLASS II MODELING GUIDANCE

The approach for the air quality modeling analysis is based on the USEPA's Guideline on Air Quality Models, incorporated as 40 CFR 51, Appendix W (USEPA 2005). Additional guidance documents to be used include the following:

- The LDEQ's Air Quality Modeling Procedures (LDEQ 2006), incorporating changes as discussed with the LDEQ and reflected in comments received from the LDEQ on the stationary source modeling protocol. These comments were incorporated and a revised and final modeling protocol submitted and approved by LDEQ (Approval letter of January 22, 2014).

- The USEPA memorandum on the guidance concerning the implementation of the 1-hour NO_2 NAAQS for the PSD program (USEPA 2010a).

- The USEPA memorandum on "Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS" (USEPA 2010b).

- The USEPA memorandum on "Draft Guidance for $PM_{2.5}$ Permit Modeling" (USEPA 2013a).

- The USEPA document regarding the "Circuit Court Decision on $PM_{2.5}$ Significant Impact Levels and Significant Monitoring Concentration – Questions and Answers" (USEPA 2013b).

3.2 AIR POLLUTANT STANDARDS AND SIGNIFICANCE IMPACT LEVELS

NAAQS and/or Louisiana ambient air quality standards have been promulgated for the following criteria pollutants: CO, lead, NO_2, ozone, PM_{10}, $PM_{2.5}$, and SO_2. NAAQS and Louisiana ambient air quality standards are summarized in Table 2. Table 3 summarizes PSD class I and II increments, SILs, and monitoring de minimis concentrations.

Table 2 State and National Ambient Air Quality Standards

Pollutant	Averaging Time	NAAQS				Louisiana Air Quality Standards
		Primary		Secondary		
		($\mu g/m^3$)	(ppm)	($\mu g/m^3$)	(ppm)	
CO	8-hour	10,000	9[(a)]	-		Same as Primary NAAQS
	1-hour	40,000	35[(a)]	-		Same as Primary NAAQS
Lead	Rolling 3-month average	0.15	-	Same as Primary NAAQS		Same as Primary NAAQS

Table 2 State and National Ambient Air Quality Standards

Pollutant	Averaging Time	NAAQS				Louisiana Air Quality Standards
		Primary		Secondary		
		($\mu g/m^3$)	(ppm)	($\mu g/m^3$)	(ppm)	
NO_2	Annual	100	0.053	Same as Primary NAAQS		Same as Primary NAAQS
	1-hour	188	0.100	-		-
Ozone	8-hour	147	0.075[(b)]	Same as Primary NAAQS		Same as Primary NAAQS
PM_{10}	24-hour	150[(c)]	-	Same as Primary NAAQS		Same as Primary NAAQS
$PM_{2.5}$	Annual	12.0[(d)]	-	15.0	-	Same as Secondary NAAQS
	24-hour	35[(e)]	-	Same as Primary NAAQS		Same as Primary NAAQS
SO_2	Annual	80[(f)]	-	-	-	Same as Primary NAAQS
	24-hour	365[(f)]	-	-	-	Same as Primary NAAQS
	3-hour	-	-	1,300	0.5	Same as Secondary NAAQS
	1-hour	195	0.075	-	-	Same as Primary NAAQS

Notes:

(a) Not to be exceeded more than once per year.

(b) The 2008 standard. The three-year average of the 4th highest daily maximum 8-hour average concentration over each year must not exceed the standard.

(c) Not to be exceeded more than once per year on average over three years.

(d) The three-year average of the weighted annual mean concentrations must not exceed the standard.

(e) The three-year average of the 98th percentile concentrations must not exceed the standard.

(f) The USEPA revoked the annual and 24-hour standards in the 2010 SO_2 rulemaking establishing the 1-hour standard and retaining the 3-hour secondary standard. However, the annual and 24-hour standards remain in effect until one year after an area is designated for the 2010 standard. The USEPA issued designations on July 25, 2013; therefore, the annual and 24-hour standards remain in effect until July 25, 2014.

Key:

$\mu g/m^3$ = microgram per cubic meter.

CO = carbon dioxide.

NAAQS = National Ambient Air Quality Standards.

PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.

$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.

ppm = parts per million.

SO_2 = sulfur dioxide.

Table 3 Prevention of Significant Deterioration (PSD) Increments, PSD Significant Emission Rates (SERs), Significant Impact Levels (SILs), and Monitoring De Minimis Concentrations Applicable to the Project

Pollutant	Averaging Period	PSD Increments ($\mu g/m^3$) Class I	PSD Increments ($\mu g/m^3$) Class II	PSD SERs (tpy)	SILs ($\mu g/m^3$)	Monitoring De Minimis Concentrations ($\mu g/m^3$)
PM_{10}	24-hour	8[(a)]	30[(a)]	15[(a)]	5	10
$PM_{2.5}$	Annual	1	4	10 of $PM_{2.5}$	0.3	
				40 of SO_2	N/A	
				40 of NO_X[(b)]	N/A	
	24-hour	2	9		1.2	0[(c)]
NO_2	Annual	2.5	25	40 of NO_X	1	14
	1-hour	-[(c)]	-[(c)]		7.5[(c)]	
Ozone	8-hour	-	-	40 of VOC or NO_X	-	VOC or NO_X emissions increase > 100 tpy
CO	8-hour	-	-	100	500	575
	1-hour	-	-		2,000	-

Notes:

(a) In addition to PM_{10}, there is a PSD SER for Total Suspended Particulate (TSP) of 25 tpy.

(b) NO_X emissions regulated unless demonstrated not to be a $PM_{2.5}$ precursor. Ammonia and VOC emissions are presumed not to be precursors. See 73 *Federal Register* 28321 for additional details.

(c) PSD Increments, SIL, and Monitoring De Minimis Concentration level for the 1-hour NO_2 standard has not been finalized. However, an interim SIL of 7.5 µg/m3 for NO_2 was provided by the USEPA in a general guidance implementation memo dated June 28, 2010. The monitoring de minimis concentration for $PM_{2.5}$ was effectively set equal to zero due to the Circuit Court decision on January 22, 2013.

Key:

$\mu g/m^3$ = microgram per cubic meter.

CO = carbon dioxide.

NAAQS = National Ambient Air Quality Standards.

NO_2 = nitrogen dioxide

NO_X = nitrogen oxide

PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.

$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.

ppm = parts per million.

SO_2 = sulfur dioxide.

USEPA = United States Environmental Protection Agency

VOC = volatile organic compounds.

3.3 BACKGROUND AIR POLLUTANT CONCENTRATIONS

For primary air pollutant compounds, i.e., pollutants directly emitted from emission sources, and secondary air pollutants (ozone, formed from the directly emitted pollutants NO_X and VOC), four monitoring stations surround Lake Charles. These are detailed in Table 4 along with the pollutants monitored at each site.

Table 4 Ambient Air Monitoring Stations near Lake Charles

Site	Distance and Direction from Project Site	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC	Ozone
Baton Rouge	130 miles to east	✓	✓	✓	✓	✓		✓
Lafayette	75 miles to east			✓	✓			✓
Carlyss	4.8 miles to northwest							✓
Lake Charles Lighthouse Lane	7.6 miles to north-northwest						✓	
Westlake	11 miles to north		✓		✓	✓	✓	✓
McNeese University	7 miles to northeast				✓			

Source: LDEQ n.d.
Key:
CO = carbon dioxide.
NO_X = nitrogen oxide.
PM_{10} = particulate matter equal to or less than 10 micrometers aerodynamic diameter.
$PM_{2.5}$ = particulate matter equal to or less than 2.5 micrometers aerodynamic diameter.
SO_2 = sulfur dioxide.
VOC = volatile organic compounds.

Magnolia evaluated the distance, direction, and surroundings of each monitoring site to select the appropriate background monitor data sites. Magnolia proposes to use the Westlake monitor site for background data for NO_X, SO_2, and ozone since it is the closest monitoring site to the Project location where these pollutants are measured and is representative of the Project location. Magnolia proposes to use $PM_{2.5}$ data from the McNeese University site, which is the closest $PM_{2.5}$ monitoring station to the Project location. There are no stations in the Lake Charles vicinity that monitor for CO or PM_{10}; the closest site where PM_{10} is monitored is in Lafayette (approximately 75 miles to the east), and CO is monitored in Baton Rouge (approximately 130 miles to the east). These latter two sites are proposed as PM_{10} and CO background data sites. While relatively distant from the Project location and surrounded by urbanized land development, they likely represent typical PM_{10} and CO concentrations for an urban/developed land type setting similar to the Project location. Due to the central city location of the Baton Rouge CO monitor, a higher influence of vehicle emissions may tend to cause data from this station to be slightly conservative (higher) than the Project site. The appropriate statistical form

of the background concentration data will be obtained from either the LDEQ or the USEPA Airs database. Adjusted background procedures as described in the LDEQ guidance will not be used.

3.4 MODEL SELECTION

The USEPA's AERMOD, Version 13350 (issued December 16, 2013), will be the regulatory dispersion model used to estimate ambient impact concentrations of emissions from the Project sources. Regulatory default options as recommended in the USEPA's Guideline on Air Quality Models will be used in the modeling analysis. The regulatory default option in AERMOD includes the use of stack-tip downwash, incorporates the effects of elevated terrain, and includes the calms and missing data processing routines.

Preprocessing programs associated with AERMOD include AERMAP (version 11103), AERSURFACE (version 13016), AERMET (version 13350) and AERMINUTE (version 11325). These are the most recent versions available. If the USEPA issues updated versions prior to the start of input data preprocessing for the Project, Magnolia will use updated versions.

3.5 SOURCE CHARACTERIZATION

All proposed emission sources, including marine sources when stationary, will be modeled as point sources. The Project emission source inventory, heat input ratings and anticipated hours of operation are presented in Table 5. Magnolia is working with potential equipment vendors for the auxiliary boiler, thermal oxidizer, emergency use engines for the emergency generator and firewater pump, and for flares to develop final specifications and emission rates. Table 6 shows preliminary stack parameters for the Project emission sources as currently known. Draft emission rates for each source are shown in Appendix A; however, final source characteristics and maximum emission rates to be modeled will represent worst-case conditions and will be presented in the modeling report and permit application after the Best Available Control Technology (BACT) analysis has been completed.

Marine Emission Sources

LNG tankers that may call on the Project facility would range in cargo capacity from 125,000 m^3 up to 218,000 m^3 capacity. LNG barges would have a cargo capacity up to 15,000 m^3. In addition, an LNG carrier calling on Magnolia's loading facilities would require the use of tug boats (three tugs of up to 7,000 horsepower [hp] each) to assist the LNG carrier while transiting through the Calcasieu River and while docking and undocking. One tug (7,000 hp) would most likely be used to maneuver an LNG barge into and away from the loading dock. For LNG carriers, the assist tugs would be released once docking is completed. However, due to the short duration for loading an LNG barge, the tug may remain with the LNG barge during loading operations.

An LNG carrier's propulsions systems may consist of a steam boiler/turbo generator system or dual-fuel diesel electric (DFDE) drive systems. Future LNG carriers may also consist of dual-engine, dual-fuel direct drive systems. After the operational date of the Project facility, any type of LNG carrier currently in use may call on the Magnolia's loading facilities. For

purposes of illustrating modeling procedures for this protocol, a DFDE propulsion system LNG carrier with cargo capacity of 175,000 m^3 is discussed. Additional modeling scenarios for other LNG carrier propulsion types may also be modeled, depending on further information becoming available on the expected numbers and types of LNG carriers calling on Magnolia's loading facilities.

The Project is being designed with a single new docking berth to accommodate LNG carriers and LNG barges. However, only one LNG carrier or one barge would be able to load LNG at any given time since there would be only one set of loading arms available. Therefore, there would be no possibility for simultaneous loading into two vessels.

It is currently projected that, on average, up to two LNG carriers per week and up to two LNG barges per week would make port calls at the Project terminal when operating at full plant capacity. Using an average LNG carrier capacity of 175,000 m^3, approximately 104 LNG carriers could load LNG at the Magnolia LNG terminal. Using a barge capacity of 15,000 m^3, 104 barge loadings also could occur per calendar year.

Current projections of port call frequency are based on the maximum nominal LNG output of 8 mtpa and average LNG carrier cargo capacity of 175,000 m^3 and 15,000 m^3 barge capacity. The actual number of port calls per week will be determined by contracts that are subsequently executed and the specific ships and barges used. The maximum number of LNG carrier and LNG barge transits per year would also be affected by the USCG's determination as part of the Waterway Suitability Assessment (WSA) process. At this time, Magnolia projects that LNG barge port calls would not begin until after Train 2 is commissioned. The projected number of port calls for marine source modeling purposes is based on potential LNG plant output alone at full plant capacity and does not reflect anticipated customer requirements or results of the WSA process, which may result in less than maximum port calls. Thus, two LNG carrier loadings and two LNG barge loadings per week for 52 weeks per year will be modeled for assessment of annual impacts. Since a range of LNG carrier sizes could call on Magnolia throughout a calendar year, for annual average purposes, an average LNG carrier size is assumed to be 175,000 m^3.

An LNG carrier call on Magnolia's loading facilities would require the use of tug boats (three tugs of up to 7,000 hp each) to assist the LNG carrier while transiting the Calcasieu River and while docking and undocking. During docking and undocking, each tug boat's engine and the LNG carrier engine would operate at varying loads as necessary for maneuvering to or from the dock. Typically, docking and undocking requires approximately one hour each to complete. At the maximum LNG loading rate of 10,000 m^3/hour, it would take approximately 12.5 hours to load a 125,000-m^3 LNG carrier, up to 21.8 hours to load a 218,000-m^3 LNG carrier. During the loading period, it is anticipated that the LNG carrier would be operating in "hoteling" mode, with propulsion engines in a hot standby mode and generator set engine operation limited to a load necessary to meet the electrical load demand from the ship's systems while docked. Power for pumping LNG to the tanker would be provided by electric motor driven pumps located onshore.

Similar procedures would be used to maneuver barges into and away from the loading dock. One tug (7,000 hp) would most likely be used to maneuver the barge into and away from

the loading dock. During this period, the tug's engines would operate at varying loads as necessary for maneuvering to or from the dock. Once docked, the tug would remain on standby (in idle mode, approximately 10 percent engine load) while the barge is loaded. A 15,000-m^3 LNG barge could be loaded in approximately two hours.

An LNG carrier and an LNG barge cannot be loaded simultaneously; therefore, only one LNG carrier or one LNG barge can be docked in the loading berth at any given time. For short-term (i.e., 1-hour to 24-hour) emission rate purposes, the worst-case short-term emission rate scenario from marine sources is expected to be the LNG carrier in hoteling mode. The LNG carrier hoteling emission scenario will be further evaluated during the modeling study to include other LNG carrier propulsion systems that may have different emission rates to assess short-term ambient impacts in conjunction with the liquefaction facility's stationary source operation. In addition, if tug boats are required to remain on standby at the dock while the LNG carrier is being loaded, tug boat emissions will be included in the modeling analysis.

For assessment of annual NO_2, SO_2, and $PM_{2.5}$ NAAQS impacts, the annual emission rate will reflect the worst-case annual emissions from the potential LNG carrier loadings (considering each type of LNG carrier that may call on Magnolia) and 104 barge loadings per year. Emission rates used in modeling would be annual tons for an LNG carrier and LNG tug/barge, each divided by 8,760 hours per year.

Fuel type and blends used by the LNG carrier may be marine diesel and/or boil-off gas for both propulsion and generator set engines. Fuel use would vary depending on the type of propulsion system employed and presence or lack of an onboard boil-off gas compressor on the LNG carrier. LNG carrier emissions are governed by the International Convention for the Prevention of Pollution from Ships (MARPOL) Annex VI of the International Maritime Organization (IMO); NO_X emission regulations are found in Regulation 13 and SO_X regulations are found in Regulation 14. Emissions for tug boats are controlled primarily through USEPA marine fuel and engine specifications. The IMO and the USEPA have established the North American Emission Control Area (NAECA) that is applicable to the entire coastlines of the United States and Canada. In calendar year 2015, all vessels operating within 200 nautical miles of the coast will be required to use fuel with a sulphur content less than 0.1 percent. The USEPA and the USCG have entered into a memorandum of understanding for enforcement of the fuel sulphur requirement in accordance with MARPOL Annex VI.

Equipment Description

Magnolia is currently evaluating emission source characteristics (e.g., stack height, diameter, exit temperature, and velocity) data for the existing LNG carrier and tug boat fleet that may be utilized on the Project. The data ultimately used in the modeling will be provided in the marine sources modeling report.

The stationary gas turbines for the Project will be aero-derivative units produced by General Electric, model PGT25+G4. Each gas turbine would combust only pipeline quality natural gas and would be equipped with dry-low emissions (DLE) and a waste heat recovery unit. Each unit's heat input rating is shown in Table 5.

Magnolia is currently in the process of obtaining proposals from potential auxiliary boiler vendors; therefore, a specific unit has not been selected at this time. The data presented in this protocol are preliminary and subject to change upon final vendor selection. However, the data presented are reasonable approximations of the performance characteristics of the boiler.

Table 5 Emission Source Equipment Inventory – Magnolia LNG Project

Equipment Type	Quantity On-Site	Heat Input Rating (MMBtu/hr)[(a)]	Expected Annual Hours of Operation
Gas Turbine	8	318.42	8,760
Auxiliary Boiler	4	96	8,760
CO_2 Vent/Thermal Oxidizer	4	20.2	8,760
Diesel Engine Firewater Pump	1	1.85	<100
Diesel Engine Emergency Generator	1	7.42	<100
Marine Flare	1	To Come	<100
Process Flare	1	To Come	<100

Note: (a) Based on higher heating value (HHV) of 1,043 Btu/scf.
Key:
Btu/scf = British thermal units per standard cubic foot
CO_2 = carbon dioxide.
MMBtu/hr = million British thermal units per hour.

Table 6 Preliminary Stack Parameter Values for Project Emission Sources

Emission Source	Stack Height (meters)	Stack Diameter (meters)	Exit Velocity (meters per second)	Exit Temperature (degrees Celsius)
Gas Turbine (each)	27	3.3	25	196
Auxiliary Boiler (each)	25	1.2	~15	149
CO_2 Vent/Thermal Oxidizer (each)	23	0.3	TBD	TBD
Cryogenic Flare	33	note 1	20	1,000
Process Flare	33	note 1	20	1,000
Emergency Generator Engine	TBD	TBD	TBD	TBD
Firewater Pump Engine	TBD	TBD	TBD	TBD

Notes:
1) Effective stack diameter to be based on calculation procedure contained in section 5.9.4 of LDEQ 2006 modeling guidance which relates resulting stack diameter to total heat release of gas being flared.
Key:
CO_2 = carbon dioxide
TBD = to be determined

The auxiliary boilers in each liquefaction train would combust a mixture of high British thermal unit (Btu) (feed gas and rich gas) and low Btu (holding and ship loading) fuel using low NO_X burners. The boiler efficiency would be approximately 84 percent. The percentage of each fuel type that would be in the fuel mixture fired in the boiler has not been developed. For the preliminary potential to emit estimate, it is assumed the composition of the fuel gas is primarily feed gas with the waste gas stream from the carbon dioxide removal system. Blending in rich gas and low Btu gas would alter the potential to emit slightly, estimated as varying by no more than 5 to 10 percent. The fuel gas stream burned in the auxiliary boiler may also contain trace amounts of benzene, toluene, ethylbenzene, and xylene (BTEX) from the carbon dioxide removal system. The estimated destruction efficiency for these hazardous air pollutants (HAPs) in the combustion process is 99.99 percent.

The thermal oxidizer would consist of a low NO_X burner firing upward into the base of a leg-supported, refractory-lined incinerator. Contaminated CO_2 (containing BTEX) would enter the unit near the base of the incinerator vessel near the burner. This physical arrangement would allow the burner to use the cool, inert waste gas as a means to reduce NO_X production during operation, resulting in a NO_X concentration of approximately 40 parts per million by dry volume at 3 percent oxygen. The feed gas would mix with the waste gas in the combustion process to form the hot flue gas that would be discharged from the unit at the top. The estimated destruction efficiency for BTEX in the combustion process is 99.00 percent. Other necessary control devices and programming would be provided to ensure that the system would start and operate safely according to National Fire Protection Association 85/86 guidelines. The thermal oxidizer vendor has not been selected at this time.

The marine and process flare would not be used during normal operation; however, a small pilot light would be continuously lit should flaring be needed. Flaring would not be used during normal operation because the boil-off-gas generated from the LNG tank would be used as fuel gas in the auxiliary boiler. However, when maintenance is required, process lines may need to be manually vented and purged. There may also be occasions of automated venting from Pressure Relief Valves, Process Shutdowns, and Emergency Shutdown. During these events, flaring will be necessary. Magnolia is developing an estimate of the frequency of flaring that will be included in the final modeling protocol. Modeling guidance for flares from Section 5.9.4 of the LDEQ modeling guidance will be used if flares are included in the worst-case modeling condition.

Vendors have not been selected for the emergency generator set or the diesel firewater pump.

3.6 EFFECTS OF NEARBY FACILITIES

Effects of nearby facilities will not be included in the preliminary dispersion modeling analysis for comparison to the SILs. If the preliminary dispersion modeling analysis shows significant impacts, an additional protocol will be submitted for the refined analysis that includes contributions from nearby facilities for comparison to PSD increment consumption.

4 AERMOD MODELING OPTIONS

4.1 BUILDING DOWNWASH

Building downwash effects will be considered in the modeling analysis. Structures and buildings will be included in the analysis when the distance between modeled stacks and the nearest part of the building is less than or equal to five times the lesser of the height or the projected width of the building. The Building Profile Input Program with Prime (BPIP-PRIME) will be used to calculate direction-specific building dimensions and good engineering practice stack heights. AERMOD uses the output from BPIP-PRIME to calculate building downwash effects.

Due to the compact footprint of each liquefaction train, each train will be considered as a solid building for input to BPIP-PRIME. Each liquefaction train has a maximum dimension of approximately 166 meters (545 feet) and minimum dimension of 44 meters (144 feet).

For modeling involving an LNG carrier, the dimensions of the vessel and any significant above-deck structure (e.g., the accommodation block typically on the stern) will be input to the model for evaluation of structure downwash. The tug/LNG barge combination does not present a significant obstruction to flow and thus will not be evaluated for building downwash.

4.2 TERRAIN

The terrain surrounding the proposed Project location up to 50 kilometers in any direction is best described as flat. A preliminary evaluation of terrain heights indicates most terrain elevations are between 0 feet and 20 feet in a 50-kilometer radius; there is a slight rise in elevation to the northwest with terrain reaching 40 to 50 feet at a distance of approximately 35 to 40 kilometers away. According to section 5.7 of the LDEQ Air Quality Modeling Procedures, requirements to consider terrain elevations are determined on a case-by-case basis. For the Project location in the Southwest Regional office region, the LDEQ typically does not require use of terrain data in dispersion modeling. However, after discussion with the LDEQ regarding implementing terrain data in flat terrain areas, Magnolia proposes to use the AERMOD Terrain Preprocessor (AERMAP Version 11103) to assign terrain elevations of source, building, and receptor locations. U.S. Geological Survey (USGS) 7.5-minute digital elevation models (DEMs) would be used for processing in AERMAP. The Project datum would be in North American Datum of 1983-Universal Transverse Mercator coordinates.

4.3 METEOROLOGICAL DATA

AERMOD will be run with surface meteorological data and upper air data from the Lake Charles Regional Airport. The airport is approximately 4.6 miles (7.5 kilometers) east-northeast of the Project site. Surface observation data will be obtained from the National Oceanic and Atmospheric Administration (NOAA) Integrated Surface Database. Upper air data will be obtained from the NOAA Earth System Research Laboratory radiosonde observation database. A five-year dataset will be used, encompassing the period 2008 through 2012. If 2013 data are

available for upper air and surface datasets, the five-year dataset will comprise years 2009 through 2013.

The processing steps to be used include determining land surface characteristics followed by processing of the land surface characteristics; surface and upper air meteorological data. The USEPA AERSURFACE program (version 13016) will be used to determine the surface characteristics surrounding the Project site. AERSURFACE processes land cover data to determine the surface characteristics for use in AERMET. AERSURFACE uses a 1-kilometer radius surrounding the site to determine surface roughness values for each direction sector, and a 10-by-10-kilometer area to determine the mid-day albedo and daytime Bowen Ratio. AERSURFACE will be run for month-specific surface characterization. The AERMET (Version 13350) pre-processor will then be used to prepare meteorological data for use in AERMOD. Output from AERSURFACE will be input to AERMET along with surface and upper air meteorological observation data. Guidance provided in the most recent AERMOD Implementation Guide (USEPA 2009) will be followed.

Surface wind data sets will consist of automatic surface observing system (ASOS) 1-minute wind data from the Lake Charles Regional airport. These data sets will be processed using the AERMINUTE data pre-processor program for subsequent use in Stage 2 of AERMET data processing.

4.4 RECEPTORS

Impacts will be analyzed at receptors placed along and beyond the fence line of the Project site. Guidance provided by the USEPA describing locations considered as ambient air will be followed. In general, the guidance states that any property owned by the Project within a fenced in area (or area with public access controlled by other means) is not considered ambient air; locations outside of fenced-in locations owned by the Project are considered ambient air, including over-water locations.

The initial receptor grid will be established using a Cartesian grid at the following intervals:

- Along fence line: 100-meter spacing.
- Fence line to 1 kilometer beyond fence line: 100-meter spacing.
- From 1 kilometer to 5 kilometers beyond fence line: 500-meter spacing.
- From 5 kilometers to 10 kilometers beyond fence line: 1-kilometer spacing.

If the initial modeling indicates ambient concentrations remain above the applicable SIL beyond 10 kilometers, the receptor grid will be extended to determine the full extent of the area of influence, not to exceed 50 kilometers (the geographic/dispersion limit of the model) from the Project fence line. SILs are defined by the USEPA as ambient concentrations of air pollutants above which the potential for a significant air quality impact is deemed possible. It follows that if modeled ambient concentrations of air pollutants are below a SIL, a significant air quality impact is not likely and no further modeling is required. If the maximum concentration occurs beyond 1 kilometer of the fence line, then an additional receptor grid with 100-meter spacing

will be set up, centered on the receptor with the maximum impact to ensure the maximum impact is identified. Receptor elevations will be determined using AERMAP as discussed in Section 4.2.

The Mossville environmental justice community is located approximately 7 miles (11.3 kilometers) north of the Project site. The initial receptor grid outlined above would extend to 6.2 miles (10 kilometers) from the Project site. As noted in the preceding paragraph, if modeled impacts are above the applicable SIL at 6.2 miles (10 kilometers), the receptor grid would be extended so that ambient concentrations at receptors beyond 6.2 miles (10 kilometers), including the Mossville area, will be determined. Discrete (i.e., individual) receptors will be placed in the Mossville community to supplement the extended grid.

4.5 ESTIMATING NO_2 MODELED CONCENTRATIONS

Emissions from a combustion source are primarily composed of two compounds, nitrogen oxide (NO) and nitrogen dioxide (NO_2), that are added together to determine total NO_X. The primary component of NO_X in the stack is NO. However, the NAAQS for this class of compounds has been established for NO_2 since NO_2 is the photochemically reactive form of NO_X that participates in ozone formation.

The USEPA has established a three tier procedure for determining the quantity of NOx emitted from an emission source that ultimately converts to NO_2 as described in the USEPA Guideline on Air Quality Models. Although the procedure was originally established to address the former annual NO_2 NAAQS, the procedures are still considered technically appropriate for the short-term NO_2 NAAQS. The tiered approach is intended to act as a screening procedure, with Tier 1 providing the most conservative result. Tiers 2 and 3 are used if unacceptable results are realized from Tier 1.

In Tier 1, full conversion of NO_X to NO_2 is assumed in modeling. If the NAAQS for NO_2 is exceeded, then the refined technique found in Tier 2 is applied.

In Tier 2, the Tier 1 1-hour modeled results will be multiplied by a NO_2 to NO_X ambient equilibrium ratio of 0.8 as recommended by the LDEQ. As in Tier 1, if the modeled results show an exceedance of the NAAQS, Tier 3 is applied.

Tier 3 consists of applying one of two non-default techniques available in the latest version of AERMOD that account for the atmospheric chemistry relationship between the conversion of NO_X to NO_2 and ambient ozone concentrations. Use of Tier 3 requires review by the USEPA as well as the LDEQ. Both techniques are fundamentally based on the limitation of NO_X to NO_2 conversion by the ambient ozone concentration and in-stack NO_X conditions. The Ozone Limiting Method (OLM) procedure applies a series of steps to determine the amount of NO_X that ultimately converts to NO_2 based on the amount of ozone present in the atmosphere. Conversion of NO_X to NO_2 is "limited" if the modeled NO_X concentration is greater than the ambient ozone concentration. The second ozone method under Tier 3 is the Plume Volume Molar Ratio Method (PVMRM). The PVMRM method takes into account more detailed information regarding the atmospheric chemistry processes in the plume resulting in conversion

of NO_X to NO_2. For both Tier 3 methods, a value for the ambient ozone concentration is required.

For this Project, the modeling analysis will apply each tier when modeling NO_2 in sequence, as necessary to demonstrate compliance with the NO_2 NAAQS. If Tier 3 becomes necessary, Magnolia will provide a supplement to this protocol to address data assumptions for the Tier 3 methodology. Proposed data to be discussed would include:

- Background ozone concentration;
- NO_2 to NO_X equilibrium ratio; and
- In-stack NO_2 to NO_X ratio for each modeled stationary source emitting NO_X. In-stack NO_2 to NO_X ratios are not available for marine emission sources.

5 CLASS I MODELING METHODOLOGY AND ADDITIONAL IMPACT ANALYSIS

5.1 CLASS I

In addition to the comparison against ambient air quality standards for Class II modeling, an analysis of air quality impacts to Class I areas must also be assessed. Class I areas include locations under the jurisdiction of the United States Fish and Wildlife Service, United States Forest Service, and the National Park Service. The Class I designation has also been given to specific Native American lands that have been determined to require special treatment for air quality purposes. The closest Class I area to the Project site is the Breton National Wildlife Refuge (approximately 420 kilometers to the east-southeast off the coast of Louisiana/Mississippi). Typically, distances greater than 300 kilometers between an emission source and a Class I area precludes the need for further Class I air quality analyses. For a source to Class I distance greater than 400 kilometers, the FLAG screening test (Q/d) is not required. Therefore, due to the separation distance of greater than 400 kilometers, a Class I air quality screening analysis and refined impact assessment will not be required.

5.2 ADDITIONAL IMPACT ANALYSIS

As part of its permit application and stationary source modeling analysis for LDEQ, Magnolia will prepare an additional impact analysis following the guidelines in Chapter D of the USEPA New Source Review Workshop Manual (USEPA 1990) to address growth and associated ambient air quality impacts, soils and vegetation impacts and visibility impairment. The growth analysis will consider the Project's potential impact and emissions associated with growth of industrial, commercial and residential sectors as a result of the Project. The soils and vegetation assessment will consider the modeled ambient concentration resulting from the Project in comparison to secondary NAAQS that have been established for the purpose of protecting plants and animals from harm due to air quality. The visibility impairment analysis will consist of a determination of the visual quality in the area and an initial screening-level assessment of the possibility of visibility impairment. If necessary, a more in-depth analysis following procedures in the USEPA's Workbook for Plume Visual Impact Screening and Analysis (USEPA 1992) would be performed if initial screening indicated a potential impact.

6 REPORTING OF RESULTS

The air quality modeling analysis will be documented in a report that includes a summary narrative and a tabulation of the model results to demonstrate compliance with the applicable ambient air quality standards and other thresholds. The report will include the following elements:

- Detailed description of the proposed activity and emission sources with specific parameters used in the analysis including emission rates, stack heights, stack diameters, temperatures, exit velocities, and nearby building dimensions;
- Facility plot plan showing the location of emission sources, facility buildings, fence line corners, and terrain characteristics;
- Map (i.e., USGS with 1:24,000 scale) showing the facility location and receptors used in the analysis;
- Description of the model(s) selected and rationale for selection;
- Description of the site topography and receptor grids used in the analysis;
- Description of meteorological data;
- Technical support documentation for any assumptions made in the modeling analysis which deviate from the stated guidance; and
- Summary of model predictions showing comparison to applicable ambient air quality standards.

Digital copies of relevant model files will be included with the report, such as, but not limited to:

- Facility plot plan (in geo-referenced digital format);
- Meteorological files (.SFC and .PFL);
- Terrain files (USGS DEM files);
- Geo-referenced maps;
- Files related to BPIP-PRIME runs; and
- AERMOD model generated input and output files.

Reports and applicable digital files will be submitted to the FERC.

7 REFERENCES

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Appendix A
Preliminary Operational Emission Estimates

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Table A1 Preliminary Potential Operation Emissions (tons per year) – Magnolia LNG								
Emission Source	NO_X	CO	SO2	PM10	PM2.5	VOC	HAPs	CO2e
Gas Turbines (8)	1,016	639	32	74	74	45	11	1,318,269
Thermal Oxidizers (4)	18	30	0.2	3	3	2	1	42,725
Auxiliary Boiler (4)	83	139	1	13	13	9	4	198,469
Emergency Generator (1)	1.5	3	0	0.02	0.02	0.7	0.13	249
Emergency Fire Water Pump (1)	0.7	1.5	0	0.01	0.01	0.4	0.06	125
Total	1,119	813	33	90	90	57	16	1,559,837

Table A2
Emissions for GE PGT25+G4/DLE
Magnolia LNG

Parameter		Units	Value
Fuel Lower Heating Value (LHV)[1]		Btu/scf	935.1
Fuel Higher Heating Value (HHV) [1]		Btu/scf	1036.4

Parameter	Units	Turbine 1	Number of Turbines	Total for Eight Turbines
Hourly Fuel Flow (LHV) - Maximum[2]	MMBtu/hr	287.30	8	2,298
Hourly Fuel Flow (LHV) - Average[3]	MMBtu/hr	287.30	8	2,298
Hourly Fuel Flow (HHV) - Maximum[4]	MMBtu/hr	318.42	8	2,547
Hourly Fuel Flow (HHV) - Average[4]	MMBtu/hr	318.42	8	2,547
Annual Operation @ 100% Load	hr/yr	8760	8	70,080
Maximum Annual Fuel Flow (LHV)[5]	MMBtu/yr	2,516,748	8	20,133,984
Maximum Annual Fuel Flow (HHV)[6]	MMBtu/yr	2,789,389	8	22,315,112
Maximum Annual Fuel Flow (volume)[6]	MMscf/yr	2,690	8	21,520

Pollutant Type	Pollutant	LHV Emission Factor (lb/MMBtu)	HHV Emission Factor[7,8,9] (lb/MMBtu)	Each Turbine		Eight Turbines	
				Maximum Hourly Emission Rate (lb/hr)	Maximum Annual Emissions (tpy)	Annual Emissions (tpy)	
Criteria	NO_X			29.00	127.02	1016.2	
	CO			18.24	79.89	639.1	
	VOC			1.28	5.61	44.9	
	PM	-	0.0066	2.10	9.20	73.6	
	PM_{10}	-	0.0066	2.10	9.20	73.6	
	$PM_{2.5}$	-	0.0066	2.10	9.20	73.6	
	SO_2	-	0.0028	0.90	3.93	31.5	
HAPs	Acetaldehyde	-	0.000040	0.013	0.056	0.4	
	Acrolein	-	0.0000064	0.002	0.009	0.1	
	Benzene	-	0.000012	0.004	0.017	0.1	
	Ethylbenzene	-	0.000032	0.010	0.045	0.4	
	Formaldehyde	-	0.00071	0.226	0.990	7.9	
	Toluene	-	0.00013	0.041	0.181	1.5	
	Xylenes	-	0.000064	0.020	0.089	0.7	
	Total HAPs	-	**-**	**0.3166**	**1.387**	**11.095**	
Greenhouse Gas	CO_2			37218	163,015	1304118.7	
	N_2O	-	0.003	0.96	4.18	33.5	CO_2e Multiplier
	CH_4	0.028	0.0255	5.13	22.46	179.7	
Greenhouse Gas (CO_2e)	CO_2	-	-	37,218	163,015	1,304,119	1
	N_2O	-	-	296	1,297	10,377	310
	CH_4	-	-	108	472	3,773	21
	Total GHGs	-	**-**	**37,622**	**164,784**	**1,318,269**	

Notes:
1. Data from GE PGT25+G4 DLE Expected Emissions.xlsx sheet (based on Fuel Number 800-41 Magnolia).
2. Data from GE PGT25+G4 Turbine Specification Sheets. Fuel flow based on inlet temperature chilled to 15.0 ^oC dry bulb.
3. Inlet cooling to be used to maintain inlet temperature, therefore little variation between hourly maximum and annual average.
4. Calculated from hourly fuel flow (LHV basis) and ratio of HHV to LHV.
5. Maximum annual fuel flow for each turbine calculated by multiplying maximum hourly fuel (LHV) by annual operation @ 100% load.
6. Calculated from maximum annual fuel flow (LHV).
7. NO_X, CO, VOC, and CH_4 emission factors from GE PGT25+G4 Turbine Specification Sheets.
8. CO_2 emission factor from GE PGT25+G4 DLE Expected Emissions.xlsx.
9. Emissions factors from United States Environmental Protection Agency (EPA). 2000. AP 42 Fifth Edition, Volume I - Section 3.1 - Stationary Gas Turbines. PM emission factors based on total PM (condensable and filterable fraction). PM_{10} and $PM_{2.5}$ emission factors assumed equal to total PM emission factor (condensable and filterable fractions). SO_2 emission factor based on sulfur content of 0.003%.

Table A3
Emissions for Emergency Generator Engine
Magnolia LNG

Parameter		Value	Units
Power Rating		1000	kW
		1341	
Engine Fuel Flow Rate (HHV)[1]		5,534	Btu/hp-hr
		7.42	MMBtu/hr
Higher Heating Value (HHV)[2]		1036.4	Btu/scf
Maximum Yearly Operation		500	hr/yr

Pollutant Type	Pollutant	HHV Emission Factor[3] (lb/MMBtu)	Emission Factor[4] (g/hp-hr)	Maximum Hourly Emission Rate[5] (lb/hr)	Annual Emissions (tpy)	
Criteria	NO_X	-	2.0	5.91	1.5	
	CO	-	4.0	11.8	3.0	
	VOC	-	1.0	2.96	0.7	
	PM	0.00999	-	0.073	0.018	
	PM_{10}	0.00999	-	0.073	0.018	
	$PM_{2.5}$	0.00999	-	0.073	0.018	
	SO_2	0.000588	-	0.0043	0.0011	
HAPs	Acetaldehyde	0.00836	-	0.061	0.015	
	Acrolein	0.00514	-	0.038	0.009	
	Benzene	0.000440	-	0.0032	0.0008	
	Ethylbenzene	0.0000397	-	0.00029	0.000072	
	Hexane	0.00111	-	0.008	0.0020	
	Formaldehyde	0.0528	-	0.39	0.10	
	Toluene	0.000408	-	0.0030	0.00074	
	Xylenes	0.000184	-	0.0013	0.00034	
	Total HAPs	**-**	**-**	**0.50**	**0.13**	
Greenhouse Gas	CO_2	110	-	803	201	CO_2e
	CH_4	1.25	-	9	2.3	Multiplier
Greenhouse	CO_2	-	**-**	803	201	1
Gas	CH_4	-	**-**	192	48	21
(CO_2e)	**Total GHGs**	**-**	**-**	**995**	**249**	

Notes:

1. Estimated based on typical unit.
2. Based on HHV used by GE for gas turbines for project.
3. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 3.2 - Natural Gas-fired Reciprocating Engines. July. Emission factors for 4-stroke lean burn engines. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensable and filterable fractions.
4. Applicable emission limits for spark-ignition emergency generators in NSPS Subpart JJJJ.
5. Emission rates, except NO_X, CO, and VOC, calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and dividing by listed HHV.

Table A4
Emissions for Fire Water Pump Engine
Magnolia LNG

Parameter		Value	Units
Power Rating		500	kW
		670	
Engine Fuel Flow Rate (HHV)[1]		2,767	Btu/hp-hr
		1.85	MMBtu/hr
Higher Heating Value (HHV)[2]		1036.4	Btu/scf
Maximum Yearly Operation		500	hr/yr

Pollutant Type	Pollutant	HHV Emission Factor[3] (lb/MMBtu)	Emission Factor[4] (g/hp-hr)	Maximum Hourly Emission Rate[5] (lb/hr)	Annual Emissions (tpy)	
Criteria	NO_X	-	2.0	2.95	0.7	
	CO	-	4.0	5.9	1.5	
	VOC	-	1.0	1.48	0.4	
	PM	0.00999	-	0.018	0.005	
	PM_{10}	0.00999	-	0.018	0.005	
	$PM_{2.5}$	0.00999	-	0.018	0.005	
	SO_2	0.000588	-	0.0011	0.0003	
HAPs	Acetaldehyde	0.00836	-	0.015	0.004	
	Acrolein	0.00514	-	0.009	0.002	
	Benzene	0.000440	-	0.0008	0.0002	
	Ethylbenzene	0.0000397	-	0.00007	0.000018	
	Hexane	0.00111	-	0.002	0.0005	
	Formaldehyde	0.0528	-	0.10	0.02	
	Toluene	0.000408	-	0.0007	0.00019	
	Xylenes	0.000184	-	0.0003	0.00008	
	Total HAPs	**-**	**-**	**0.12**	**0.03**	
Greenhouse Gas	CO_2	110	-	201	50	CO_2e
	CH_4	1.25	-	2	0.6	Multiplier
Greenhouse	CO_2	-	**-**	201	50	1
Gas	CH_4	-	**-**	48	12	21
(CO_2e)	**Total GHGs**	**-**	**-**	**249**	**62**	

Notes:
1. Estimate.
2. Based on HHV used by GE for gas turbines for project.
3. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 3.2 - Natural Gas-fired Reciprocating Engines. July. Emission factors for 4-stroke lean burn engines. All PM emitted assumed to be PM_{10}/$PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensible and filterable fractions.
4. Applicable emission limits for spark-ignition emergency generators in NSPS Subpart JJJJ.
5. Emission rates, except NO_X, CO, and VOC, calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and dividing by listed HHV.

Table A5
Emissions for Thermal Oxidizer
Magnolia LNG

Parameter		Value	Units
Fuel Flow Rate (HHV)[1]		20.23	MMBtu/hr
Higher Heating Value (HHV)[2]		1043	Btu/scf
Maximum Yearly Operation		8760	hr/yr

Pollutant Type	Pollutant	AP42 Emission Factor[3] (lb/MMscf)	HHV Emission Factor[3] (lb/MMBtu)	Maximum Hourly Emission Rate (each)[4] (lb/hr)	Annual Emissions for Four Units (tpy)	
Criteria	NO_X	50.00	0.0501	1.01	17.8	
	CO	84.000	0.0842	1.70	29.8	
	VOC	5.5000	0.0055	0.11	2.0	
	PM	7.6	0.0076	0.15	2.7	
	PM_{10}	7.6	0.0076	0.15	2.7	
	$PM_{2.5}$	7.6	0.0076	0.15	2.7	
	SO_2	0.600000	0.0006	0.01	0.2	
HAPs	2-methylnapthalene	0.000024	0.000000	0.0000	0.000	
	Anthracene	0.000002	0.000000	0.0000	0.000	
	Benzene	0.0021	0.000002	0.0083	0.145	
	Dichlorobenzene	0.0012	0.000001	0.0000	0.000	
	Hexane	1.8000	0.001804	0.0365	0.640	
	Formaldehyde	0.0750	0.000075	0.0015	0.027	
	Napthalene	0.0006	0.000001	0.0000	0.000	
	Toluene	0.0034	0.000003	0.0244	0.427	
	Xylene	0.0000	0.000000	0.0280	0.490	
	Total HAPs	**-**		**0.07**	**1.24**	
Greenhouse Gas	CO_2	120000	120.2999	2433.67	42,637.840	CO_2e
	N2O	0.64	0.0006	0.01	0.227	
	CH_4	2.30	0.0023	0.05	0.817	Multiplier
Greenhouse Gas (CO_2e)	CO_2	-		2,434	42,638	1
	N2O			4	70	310
	CH_4	-		1	17	21
	Total GHGs	**-**		**2,439**	**42,725**	

Notes:

1. Estimate from preliminary design data from Magnolia LNG.
2. Based on HHV for feed gas for project used for aux boiler and thermal oxidizer spec.
3. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 1.4. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensable and filterable fractions.
4. Emission rates calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and dividing by listed HHV. Emission of benzene, toluene and xylene include contribution from pilot fuel and waste gas stream.

Table A6: Estimated BTEX Destruction Efficiency

	Aux. Boiler Fuel			Thermal Oxidiser		
Destruction Efficiency		**99.99%**			**99.00%**	
	INLET	**OUTLET**		**INLET**	**OUTLET**	
	Mass Flow (kg/hr)	**Mass Flow, t/yr**		**Mass Flow (kg/hr)**	**Mass Flow, t/yr**	
CO2	0.005			10502.0366		
Nitrogen	0.014			0.0000		
Methane	73.511			5.4082		
Ethane	75.195			0.5032		
Propane	79.130			0.1054		
i-Butane	67.528			0.0000		
n-Butane	103.827			0.0000		
i-Pentane	199.821			0.0000		
n-Pentane	347.825			0.0000		
n-Hexane	534.789		lb/hr	0.0000		lb/hr
Benzene	137.574	0.121	0.030329	0.3735	0.033	0.008234
Cyclohexane	50.163	0.044	0.011059	0.0000		
n-Heptane	227.860			0.0000		
Toluene	41.926	0.037	0.009243	1.1015	0.096	0.024283
n-Octane	25.997			0.0000		
p-Xylene	16.108	0.014	0.003551	1.2691	0.111	0.027979
E-Benzene	16.108	0.014	0.003551	0.0000		
H2S	0.001			1.9553		
Ammonia	0.000			0.0000		
H2O	0.000			0.0000		
Total	**1997.382**	**0.229**		**10512.753**	**0.240**	
For 4 Trains		0.92			0.96	
Total MLNG Plant		**1.88**	**t/yr**			

Table A7
Emissions for Auxiliary Boiler
High BTU Feed Gas and Waste Gas
Magnolia LNG

Parameter		Value	Units
Fuel Flow Rate [1]		92,130	ft3/hr
		96.00	MMBtu/hr
Higher Heating Value (HHV)[1]		1043	Btu/scf
Maximum Yearly Operation		8760	hr/yr

Pollutant Type	Pollutant	AP42 Emission Factor[3] (lb/MMscf)	HHV Emission Factor[3] (lb/MMscf)	Maximum Hourly Emission Rate[4] (lb/hr)	Annual Emissions (tpy)	Annual Emissions Four Units (tpy)	
Criteria	NO_X	50	51.1275	4.71	20.6	82.53	
	CO	84	85.8941	7.91	34.7	138.64	
	VOC	5.5	5.6240	0.52	2.3	9.08	
	PM	7.6	7.7714	0.72	3.136	12.54	
	PM_{10}	7.6	7.7714	0.72	3.136	12.54	
	$PM_{2.5}$	7.6	7.7714	0.72	3.136	12.54	
	SO_2	0.60	0.6135	0.06	0.2476	0.99	
HAPs	2-methylnapthalene	0.000024	0.0000	0.00000	0.000	0.00	
	Anthracene	0.000002	0.0000	0.00000	0.000	0.00	
	Benzene	0.0021	0.0021	0.03053	0.1337	0.53	
	Cyclohexane	0.0000	0.0000	0.01106	0.0484	0.19	
	Dichlorobenzene	0.0012	0.0012	0.00011	0.000495	0.00	
	Ethylbenzene	0.0000	0.0000	0.00355	0.0156	0.06	
	Hexane	1.8000	1.8406	0.16957	0.7427	2.97	
	Formaldehyde	0.0750	0.0767	0.00707	0.03	0.12	
	Napthalene	0.0006	0.0006	0.00006	0.00	0.00	
	Toluene	0.0034	0.0035	0.00032	0.00140	0.01	
	Xylene	0.0000	0.0000	0.00355	0.0156	0.06	
	Total HAPs			**0.22**	**0.99**	3.96	
Greenhouse Gas	CO_2	120000	122705.8824	11304.89	49,515	198,062	
	N_2O	0.64	0.6544	0.06	0	1	CO_2e Multiplier
	CH_4	2.30	2.3519	0.22	1	4	
Greenhouse Gas (CO_2e)	CO_2			11,305	49,515	198,062	1
	N_2O			19	82	327	310
	CH_4			5	20	80	21
	Total GHGs			**11,328**	**49,617**	198,469	

Notes:
1. From Babcock & Wilcox P55-6356_BW_Budget_R01.pdf Oct 15 2013.

2. Emission factors from United States Environmental Protection Agency (EPA). 2000b. AP 42 Fifth Edition, Volume I - Section 1.4. All PM emitted assumed to be $PM_{10}/PM_{2.5}$. PM, PM_{10}, and $PM_{2.5}$ emission factors include condensable and filterable fractions.
3. Emission rates calculated from EPA emission factors and fuel flow. Since emission factors are based on heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by ratio of actual fuel heat value divided by 1020.
4. Emission rates calculated from EPA emission factors and fuel flow. Since emission factors are based on higher heating value (HHV) of 1020 Btu/scf, rates corrected by multiplying by 1020 and dividing by listed HHV. Emission of benzene, toluene and xylene include contribution from pilot fuel and waste gas stream.

Table A8
Natural Gas Composition Data
Magnolia LNG

Component	Molar (Volume) Fraction[1] (wgt %)	Component Molecular Weight (lb/lbmole)	Weighted Sum Flash Gas Molecular Weight (lb/lbmole)	Weight Fraction (wgt %)
Nitrogen	1.014	28.01	0.284	1.692
Carbon Dioxide	0.01	44.01	0.003	0.02
Methane	95.60	16.04	15.34	91.3
Ethane	2.56	30.07	0.770	4.58
Propane	0.32	44.10	0.143	0.852
I-Butane	0.091	58.12	0.053	0.316
N-Butane	0.091	58.12	0.053	0.316
I-Pentane	0.0811	72.15	0.059	0.348
N-Pentane	0.0811	72.15	0.059	0.348
Hexanes	0.035	95.96	0.033	0.197
Total	**99.9**	**-**	**16.79**	**100.0**

HAP Component	Molar (Volume) Fraction[2] (wgt %)	Component Molecular Weight (lb/lbmole)	Weighted Sum Flash Gas Molecular Weight (lb/lbmole)	Weight Fraction (wgt %)
Benzene	0.00310	78.114	0.00242	0.0144
Ethylbenzene	0.00002	106.167	0.00002	0.000109
n-Hexane	0.00100	86.177	0.00086	0.0051
Toluene	0.00100	92.141	0.00092	0.00549
Xylenes	0.00100	106.167	0.00106	0.00632
Total HAPs	**0.0061**	-	-	**0.0315**

Component	Weight Fraction in Natural Gas (wgt %)	Weight Fraction in TOC (wgt %)
TOC	98.3	100
Methane	91.3	92.9
VOC	2.38	2.42
Benzene	0.0144	0.0147
Ethylbenzene	0.000109	0.000111
n-Hexane	0.005	0.005
Toluene	0.00549	0.00558
Xylenes	0.00632	0.00643
Total HAPs	0.0315	0.0320

Notes:

1. Based on Fuel Number 800-41 Magnolia provided by GE for PGT25+G4 DLE emissions.

2. Component split based on GRI GLY-Calc V4.0 lumped C6+ gas analysis multipliers for the Natural Gas Transmission Industry Segment.

Table A9 - LNG Vessel Operational Emissions - Revised

SLOW SPEED DIESEL without reliquefaction

		Nat Gas	Units	Tugs Diesel	Units	Oil	Units
Emission	NOx	1.3	g/kW-hr	13.32	g/kW-hr	17	g/kW-hr
Factors	CO	1.1	g/kW-hr	1.69	g/kW-hr	5.8	g/kW-hr
	VOC	0.5	g/kW-hr	0.61	g/kW-hr	0.58	g/kW-hr
	PM	0.05	g/kW-hr	0.51	g/kW-hr	0.5	g/kW-hr
(Tug factor based on 1%S marine diesel)	SO2	0.05	g/kW-hr	3.92	g/kW-hr	12.9	g/kW-hr
	CO2	420	g/kW-hr	721.3	g/kW-hr	580	g/kW-hr

Assumptions

LNG Carrier speed at rated power = 19 knots

Efs from Wartsila 50DF and American Shipping Bureau

95% Nat Gas/5% HFO used on inbound and outbound trip in propulsion engines - revised based on info from MAN diesel regarding ME-GI propulsion

99% Nat Gas/1% MDO used in generator set engine for Hoteling

0.1 Estimated effect of Nonroad fuel requirement on sulfur content after June 1, 2007 (90% reduction).

Annual Carrier dockings (175K m3 vessel)	104	berthings/yr	berthings based on 2/week as stated in RR1
Annual Barge dockings (15K m3 barge)	104	berthings/yr	berthings based on 2/week as stated in RR1

Total Power LNG Carrier	30,575	bhp	22,800 kW	LNG power based on typical 175K m3 DFDE LNG carrier
Total Power (3 assist Tugs)	21,000	bhp	15,698	
Total Power (2 assist Tugs)	14,000	bhp	10,465 kW	
Total Power (1 assist Tug)	7,000	bhp	5,233 kW	

LNG Carrier and Assist Tugs

							Activity Emissions (lb)						Annual Emissions (tpy)					
Vessel	**Activity**	**Duration (hr)**	**Engine Load (%)**	**Total Engine Power (bhp)**	**Total Engine Power (kW)**	**Natural Gas Flow (MMBtu/hr)**	**NOx**	**CO**	**VOC**	**PM**	**SO2**	**CO2**	**NOx**	**CO**	**VOC**	**PM**	**SO2**	**CO2**
LNG Carrier	10.4 n. miles out to shore @ 12 knots	0.9	80%	24460	18240	178.6	73	47	18	3	24	14973	3.8	2.43	0.92	0.13	1.26	778.61
Inbound	Shore up Calcasieu to Magnolia 22 n. miles @ 5 knots	4.4	20%	6115	4560	44.6	92	59	22	3	31	18932	4.8	3.07	1.16	0.17	1.59	984.45
95%Natural Gas	Maneuvering near dock ships power	1.0	10%	3057.5	2280	22.3	10	7	3	0	3	2151	0.5	0.35	0.132	0.02	0.18	111.87
5% Residual oil	**Subtotal**	**6.3**	-	-	-	-	**176**	**112**	**42**	**6**	**58**	**36056**	**9.1**	**5.8**	**2.21**	**0.3**	**3.0**	**1875**
	Hoteling while loading	**18.0**	10%	3057.5	2280	22.3	132	104	45	5	16	38145	6.9	5.40	2.356	0.26	0.84	1983.53
LNG Carrier	Maneuvering away from dock ships power	1.0	10%	3057.5	2280	22.3	10	7	3	0	3	2151	0.5	0.35	0.132	0.02	0.18	111.87
Outbound	Transit from dock to Gulf shore line @avg 5 kts	4.4	20%	6115	4560	44.6	92	59	22	3	31	18932	4.8	3.07	1.16	0.17	1.59	984.45
95%Natural Gas	Shore to 10.4 n. miles out @ 12 knots	0.9	80%	24460	18240	178.6	75	48	18	3	25	15490	3.9	2.51	0.95	0.14	1.30	805.46
5% Residual oil	**Subtotal**	**6.3**					**178**	**114**	**43**	**6**	**59**	**36572**	**9.3**	**5.9**	**2.24**	**0.3**	**3.1**	**1901.8**
	1 tug transit from port to meet Carrier 3 n. mi. offshore (25 n. miles @ 10 kts)	2.5	80%	5600	4186	n/a	307	39	14	12	90	16641	16	2	1	1	0.470	865
Tug Boats	1 tug transit alongside Carrier to Magnolia (25 n. mi. at 6 kts)	4.5	50%	3500	2616	n/a	346	44	16	13	136.1	18721.4	18.0	2.28	0.82	0.69	0.708	973.511
	2 addnl tugs transit from port to meet Carrier 3.0 n.mi. from Magnolia (3 n. mi. @ 10 knts)	0.3	80%	11200	8372	n/a	74	9	3	3	22	3993.9	4	0	0	0	0.113	208
	2 addnl tugs transit alongside Carrier to Magnolia (3.0 n.mi. at 6 kts.)	0.5	50%	7000	5233	n/a	77	10	4	3	23	4160.3	4	1	0	0	0.118	216
Diesel	3 tugs assist carrier dock at Magnolia, release after docking	1.0	90%	18900	14128	n/a	415	53	19	16	163.3	22465.6	21.6	2.74	0.99	0.83	0.849	1168
	3 tugs full power push/tow away from dock	1.0	90%	18900	14128	n/a	415	53	19	16	163.3	22465.6	21.6	2.74	0.99	0.83	0.849	1168
	2 tugs transit alongside Carrier to 3.0 n. mi. from Magnolia and release (3 n. mi. at 6 kts)	0.5	50%	7000	5233	n/a	77	10	4	3	30.2	4160.3	4.0	0.51	0.18	0.15	0.157	216.336
	2 tugs transit back to port from release of Carrierat 3 n. mi. from Magnolia (3 n.mi. at 10 kts)	0.3	80%	11200	8372	n/a	74	9	3	3	22	3993.9	4	0	0	0	0.113	208
	1 tug transit alongside Carrier to release 3 n.mi. offshore (25 n. mi. @ 6 kts)	4.5	50%	3500	2616	n/a	346	44	16	13	136.1	18721.4	18.0	2.28	0.82	0.69	0.708	973.511
	1 tug transit back to port from release of Carrier 3 n. mi. offshore (25 n.mi. @ 10 kts)	2.5	80%	5600	4186	n/a	307	39	14	12	90	16641.2	16	2	1	1	0.470	865
	Subtotal	**17.6**					**2436.9**	**309.2**	**111.6**	**93.3**	**876.0**	**131964.8**	**126.7**	**16.1**	**5.8**	**4.9**	**4.6**	**6862.2**
	Tug boat pushing empty barge to dock (10 n. mi. @ 5 kts.)	2.0	90%	6300	4709	n/a	277	35	13	11	81	14977	14.4	1.8	0.7	0.6	0.4	779
Barge Loading	Tug boat maneuvering barge to dock	1.0	90%	6300	4709	n/a	138	18	6	5	41	7489	7.2	0.9	0.3	0.3	0.2	389
One Tug Boat	Tug boat standby while barge loaded	2.0	10%	700	523	n/a	31	4	1	1	9	1664	1.6	0.2	0.1	0.1	0.0	87
	Tug boat maneuvering barge away from dock	1.0	90%	6300	4709	n/a	138	18	6	5	41	7489	7.2	0.9	0.3	0.3	0.2	389
	Tug boat pushing barge to destination (10 n. mi. @ 5 kts.)	2.0	90%	6300	4709	n/a	277	35	13	11	81	14977	14.4	1.8	0.7	0.6	0.4	779
	Subtotal						**860**	**109**	**39**	**33**	**253**	**46595**	**45**	**6**	**2**	**2**	**1**	**2423**
TOTAL							**3783**	**749**	**282**	**143**	**1263**	**289334**	**196.7**	**38.9**	**14.7**	**7.5**	**12.8**	**15045**

Notes: 1 tug meets carrier 3 n. mi. offshore

2 addnl tugs meet carrier 3.5 miles (3.01 n. mi.) from Magnolia

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Appendix 9.C.3

Modeling Protocol - Ozone Impact Analysis of the Proposed Magnolia LNG Project

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Magnolia LNG LLC
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Houston, TX 77002
713-815-6900
www.magnolialng.com

March 25, 2014

Via Email and UPS

Tegan Treadaway
Louisiana Department of Environmental Quality
Air Quality Supervisor
P.O. Box 4313
Baton Rouge, LA 70821-4313

Re: Magnolia LNG Ozone Study Protocol and Request for Time Extension for the Magnolia LNG Dispersion Modeling Protocol Approved on January 22, 2014

Dear Tegan,

Magnolia LNG LLC, (Magnolia) is pleased to submit the enclosed protocol "Ozone Impact Analysis of the Proposed Magnolia LNG Project" for LDEQ's review. Magnolia is utilizing the services of Alpine Geophysics, LLC (Alpine) for the study.

Although a detailed photochemical modeling analysis for ozone is not required by regulation, Magnolia understands LDEQ's interest in evaluating facility ozone impacts on a case-by-case basis to allow decision makers to understand the potential ozone impacts of the proposed Project. The protocol describes the study approach, model to be used, and method for evaluating results. Ozone impact assessment modeling will utilize the Comprehensive Air Quality Model with Extensions (CAMx) in conjunction with the 17 August through 31 October 2010 ozone episode.

Magnolia also requests an approval time extension for the Magnolia LNG Dispersion Modeling Protocol approved by LDEQ on January 22, 2014. Magnolia is continuing work on the dispersion modeling study and refining emission source input data.

We appreciate LDEQ's review of the ozone modeling study protocol, and consideration of the approval extension request for the Dispersion Modeling Study protocol. Please indicate if LDEQ will forward the Ozone Study protocol to USEPA Region 6 for their review as well. Should you have any questions or require any additional information, please do not hesitate to contact myself at 713-815-6930 or khassan@magnolialng.com; Bruce Wattle at 716-684-8060 ext. 2572 or bwattle@ene.com; or Bill Daughdrill at 850-435-8925 ext. 4303 or wdaughdrill@ene.com.

Thank you,

Komi O. Hassan

Enclosure:

cc: Bryan Johnston, Yvette Olmos

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MAGNOLIA LNG PROJECT

Modeling Protocol

Ozone Impact Analysis of the Proposed Magnolia LNG Project

25 March 2014

Submitted to:

Louisiana Department of Environmental Quality

Submitted by:

MAGNOLIA LNG

Magnolia LNG, LLC
1001 McKinney, Suite 400
Houston, TX 77002

Prepared by:

ALPINE GEOPHYSICS
Atmospheric & Hydrologic Sciences

ecology and environment, inc.
Global Environmental Specialists

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Final Modeling Protocol

Ozone Impact Analysis of the Proposed Magnolia LNG Project

Prepared for:

Ecology and Environment, Inc.
368 Pleasant View Dr.
Lancaster, NY 14086

And

Magnolia LNG, LLC
1001 McKinney, Suite 400
Houston, TX 77002

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25 March 2014

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List of Acronyms

BPA	Beaumont/Port Arthur
BRMSA	Baton Rouge Metropolitan Statistical Area
BRNAA	Baton Rouge Non-attainment Area
BSCF	Billion Standard Cubic Feet
CAIR	Clean Air Interstate Rule
CAMx	Comprehensive Air Quality Model with Extensions
CHP	Combined Heat and Power
DVc	Current Year Design Value
DVf	Future Year Design Value
EPA	United States Environmental Protection Agency
HGB	Houston/Galveston/Brazoria
LDEQ	Louisiana Department of Environmental Quality
LLC	Limited Liability Corporation
LNG	Liquefied Natural Gas
MATS	Modeled Attainment Test Software
MTPA	Million (metric) Tonnes Per Anum
NAAQS	National Ambient Air Quality Standard
NOx	Oxides of Nitrogen
OSMR®	Optimized Single Mixed Refrigerant
PPB	Parts per Billion
RRF	Relative Response Factor
SMOKE	Sparse Matrix Operator Emissions
SMR	Single Mixed Refrigerant
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds
WRF	Weather/Research/Forecast Meteorological Model

1 INTRODUCTION

1.1 Overview

Magnolia LNG, LLC (Magnolia) is proposing to develop a liquefied natural gas (LNG) facility capable of producing a nominal capacity of approximately 8.0 million (metric) tonnes per annum (mtpa) of LNG using its highly efficient and patented Optimized Single Mixed Refrigerant (OSMR®) technology. The Project would receive natural gas via a tie-in to an existing interstate pipeline that traverses the proposed Project site.

The natural gas would be treated, liquefied, and stored on-site in two full containment LNG storage tanks with a net pumpable capacity of approximately 160,000 cubic meters (m^3) of LNG each. At full plant capacity, the Project would consist of four LNG trains each with a nominal capacity of 2.0 mtpa of LNG (total nominal capacity of approximately 8.0 mtpa). The LNG would be loaded onto LNG carriers for export overseas; LNG carriers and barges for domestic marine distribution and the possibility of LNG bunkering; and LNG trucks for road distribution to LNG refueling stations in Louisiana and the surrounding states. The Project site is well-positioned to provide access for loading of LNG carriers and also for potential LNG barges and LNG trucks.

Approximately 1.4 billion standard cubic feet per day (Bscf/d) of natural gas would be contracted for transportation to the Project site via the interstate pipeline to support Project operations. The core of each LNG train would be a single mixed refrigerant (SMR) process. This simple SMR process is then optimized by the use of three proven technologies: aero-derivative gas turbines, combined heat and power (CHP) technology, and ammonia auxiliary refrigeration. The integration of these proven technologies to enhance the SMR process resulted in the patented OSMR® process technology.

The Project would be located on the Industrial Canal South Shore Port of Lake Charles Tract 475, an approximately 115-acre parcel of land in Calcasieu Parish, south of Lake Charles, available through a long-term lease with the Lake Charles Harbor & Terminal District (the Port). The Industrial Canal is located off the main Calcasieu River Ship Channel. The Project would be located in an area zoned for heavy industrial use and would be consistent with other industrial facilities along the shoreline. The coordinates of the proposed Project site are as follows: Latitude: 30° 06′ 20.30″ N; Longitude: 93° 17′54.00″ W. Figure 1-1 is a general location map of the Project.

This report summarizes the photochemical grid modeling to be performed for determining 8-hour ozone impacts from emissions from the proposed project. The proposed site for the Project is located in Calcasieu Parish which is currently designated as attainment for 8-hour ozone. However, it is nearby to parishes in the Baton Rouge Metropolitan Statistical Area (BRMSA) that are designated as nonattainment for 8-hour ozone, the Houston/Galveston/Brazoria ozone non-attainment area and the Beaumont/Port Arthur area. Due to the quantity of ozone precursor

emissions and its proximity to these areas, a modeling analysis is proposed to quantify its potential impact on ozone concentrations in the surrounding area.

A detailed photochemical modeling analysis for ozone is not required by regulation. Facility ozone impacts are handled on a case-by-case basis. This modeling is to be performed external to the statutory permit process in order to allow decision makers to better understand the potential ozone impacts of the proposed project. Furthermore, guidance does not exist on application, analysis or interpretation of single source ozone impact analyses. Thus, the analysis and interpretation of the results is handled in an ad-hoc, case by case basis. In the absence of specific guidance, the modeling will be conducted using both the suggestions by EPA Region 6, and the only guidance available, namely the application of photochemical models for attainment of the ozone National Ambient Air Quality Standard (NAAQS).

1.2 Study Approach

The potential 8-hr ozone impact of the proposed project emissions will be quantified using the state-of-science regional photochemical model, the Comprehensive Air Quality Model with Extensions (CAMx) in conjunction with the 17 August through 31 October 2010 ozone episode prepared for the Louisiana Department of Environmental Quality (LDEQ). The general methodology of using the CAMx model and the LDEQ CAMx modeling platform was recommended by U.S. EPA, Region 6 and has been used for the Nucor Steel pig iron plant in Baton Rouge, the Cheniere Sabine Pass Liquefaction, and Cameron LNG facilities in Cameron Parish, Louisiana, and the Sasol North America Lake Charles Cracker Complex and Gas-to-Liquids projects in Calcasieu Parish.

The LDEQ CAMx model was prepared for the 2008 8-Hour Ozone NAAQS Modeling Project[1] and fully described in the August 2013 Technical Support Document[2].

This analysis will consist of running the CAMx photochemical model three times. Two simulations (base.run17typ – 2010 typical base case and fy2017.run17 – 2017 future case) have already been performed to confirm proper operation of the modeling system on the Alpine Geophysics, LLC computer system. In comparison with the simulation provided by LDEQ, the Alpine simulation agreed to within $1x10^{-6}$ ppb for ozone. This level of agreement was expected because the modeling was conducted with the same model executable, input files, and computer platform as the simulation conducted by the LDEQ contractor. However, this initial assessment was necessary to confirm that the modeling platform transfer did not impact the modeling results.

The third and final simulation will be identical to the base case except that the estimated projected maximum allowable emissions from Magnolia LNG project will be added to the future year elevated point source emissions files to quantify the impact.

The CAMx modeling results will be analyzed in a manner consistent with EPA guidance on application of photochemical models for attainment of the ozone NAAQS[3] , namely the Relative Response Factor (RRF) approach, and using an absolute impact approach. The RRF approach, as well as other details of the analyses, are described more fully in Section 2.

1http://www.deq.louisiana.gov/portal/DIVISIONS/AirPermitsEngineeringandPlanning/NationalAmbientAirQualityStandards/Ozone/20088HourOzoneNAAQSModelingProject.aspx

2http://www.deq.louisiana.gov/portal/Portals/0/AirQualityAssessment/Engineering/Ozone/LDEQ_TSD_4Oct13.pdf

3 EPA, 2007. "Guidance on The Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze", EPA-454/B-07-002. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC. April. (262 pgs.)

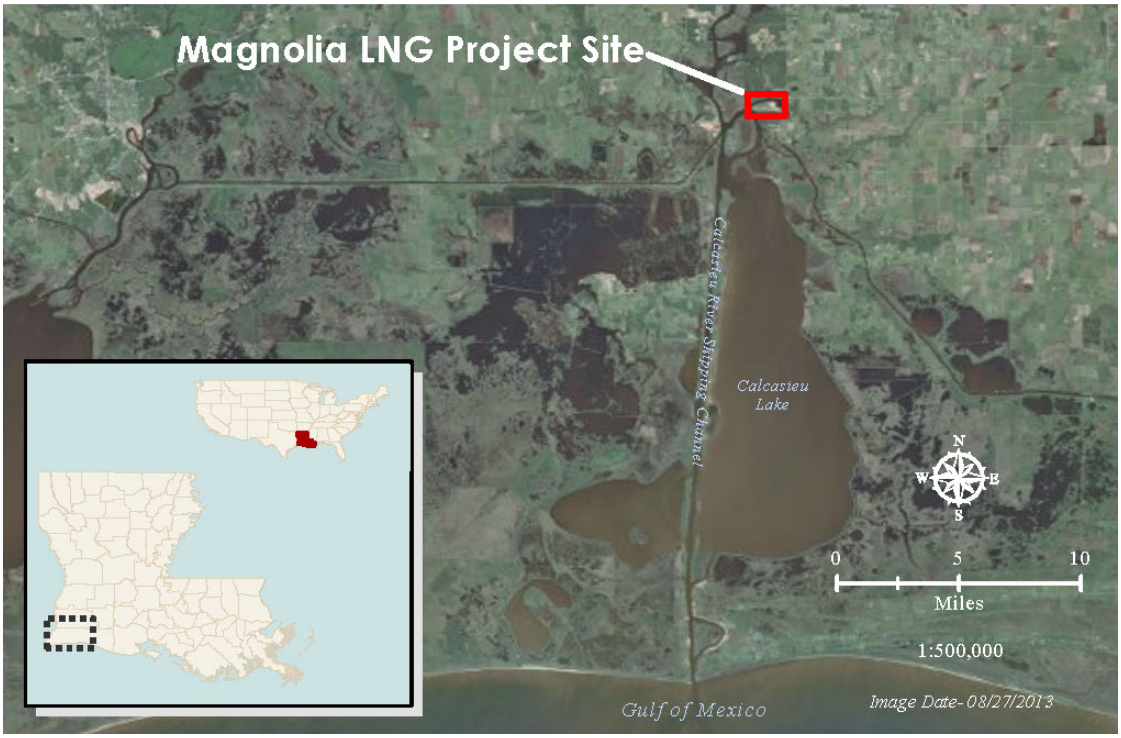


Figure 1-1: General Location Map of the Magnolia LNG Project

2 Technical Approach

The incremental 8-hr ozone impacts due to emissions from the proposed facility will be quantified within the Baton Rouge, Lake Charles, Beaumont/Port Arthur and Houston areas. This section expands on the CAMx modeling methodology, emissions input assumptions, and analysis procedures presented in Section 1.1.

2.1 Project Emissions and Stack Parameters

The emissions for the proposed facilities will be processed using the Sparse Matrix Operator Emissions (SMOKE) emissions model to prepare the hourly, speciated elevated point source format required by CAMx. The photochemical modeling will use the same stack parameters used in the AERMOD modeling. Since the LDEQ 2010 CAMx modeling did not include a Plume-in-Grid treatment for any sources, the project sources will not be treated as Plume-in-Grid sources.

2.2 17 Aug – 31 October 2010 CAMx Modeling Data Bases

The final (Run 15) CAMx modeling files for the 17 Aug – 31 October 2010 modeling episode have been obtained on external hard drive from the LDEQ. This modeling was conducted on a 36/12/4 kilometer (km) nested grid configuration shown in Figure 2-1. (LDEQ, 2007; LDEQ, 2008; LDEQ, 2009). Consistent with the analysis by LDEQ, the analysis will be restricted to the 4km domain shown in Figure 2-2.

2.3 Application of EPA Guidance for Ozone Modeling of the NAAQS

The CAMx modeling results will be analyzed in a manner consistent with EPA guidance on application of photochemical models for attainment of the ozone NAAQS (USEPA, 2007). USEPA guidance for projecting future 8-hour ozone concentrations recommends using the photochemical grid model in a relative sense to scale current observed 8-hour design values. A design value is defined as a 3-year average of the fourth highest daily maximum 8-hour ozone concentrations at a monitor. Model scaling factors, referred to as relative response factors (RRFs), are used to scale the observed design values in order to predict future year design values. RRFs are the ratio of the future year (or a project impact case) to the current-year modeled 8-hour ozone concentrations near a monitor site. USEPA has defined "near the monitor" to be approximately 15 km from the monitor location. The future-year design value (DVf) is obtained from the current-year design value (DVc) using the relation:

$$DVf = DVc \times RRF$$

The RRFs are calculated for all days in which the current-year modeled 8-hour ozone value is above a threshold. This is done so that the model response to future changes in emissions is

considered only on high ozone days of comparable conditions to the days used to produce the DVc. USEPA recommends a threshold between 70 and 85 ppb.

To perform the 8-hour projections, USEPA has developed the Modeled Attainment Test Software (MATS) tool that uses modeling results, 8-hour ozone design values and follows USEPA guidance (USEPA 2007) to project 8-hour ozone concentrations that reflect the change in emissions from the base case to an alternative emissions scenario.

EPA recommends using a DVc based on an average of three year 8-hour ozone Design Values that span 5 consecutive years centered on the modeling year (i.e., a weighted average of 5 years of fourth highest daily maximum 8-hour ozone concentrations). For example, for the 2010 baseline modeling year used in this analysis, this would mean the DVc at a given monitor would be the weighted average of the fourth highest 8-hour daily maximum ozone at that monitor from the years 2008, 2009, 2010, 2011 and 2012 using weights of 1, 2, 3, 2 and 1, respectively. To develop RRFs, EPA guidance recommends using current and future modeling results for all days in which the current year daily maximum 8-hour ozone concentration near the monitor exceeds an ozone threshold value. For a 4-km grid, as in the Baton Rouge Redesignation modeling, the maximum modeled daily maximum 8-hour ozone concentration in a 7 x 7 array of grid cells centered on the monitor is used. EPA recommends using an 8-hour ozone threshold concentration of 85 ppb and also recommends that RRFs be based on a minimum of 5 days, although a total of 10 days or more is preferred. EPA allows a reduction of the threshold value to 70 ppb to meet the minimum 5-10 days requirement.

The 8-hour ozone projections will be performed twice. The first projection will be performed using the 2010 typical simulation (base.run17typ) and the Future Year Base Case (fy2017.run17). Projections will then be run comparing the project emissions case to the 2010 typical simulation (base.run17typ). The project impacts are the differences in the future design values between the project emissions simulations and the Future Year Base case simulation.

2.4 Application of 8-hr Ozone Impact Metrics

EPA has not determined a significance threshold for ozone impacts, nor has it developed a strict guidance for metrics to use for assessing single source ozone impacts. Rather, the determination of metrics, and the interpretation of these metrics, is handled on a case-by-case basis.

In addition to the previously described application of the ozone modeling for the NAAQS, a variety of graphical displays and metrics will be used to assess and quantify the ozone air quality impacts associated with the proposed facility. These metrics were selected by USEPA Region 6 in assessing the Nucor Steel facility near Baton Rouge, LA (McNally, 2008). The modeling protocol prepared by USEPA Region 6 is presented in Appendix A. Since the time this protocol was prepared, U.S. EPA Region 6 has suggested lowering the thresholds from 80 parts per billion (ppb) to 75 ppb to better reflect the updated ozone National Ambient Air Quality Standard (NAAQS), and lowering the impact threshold from 0.3 to 0.2 ppb.

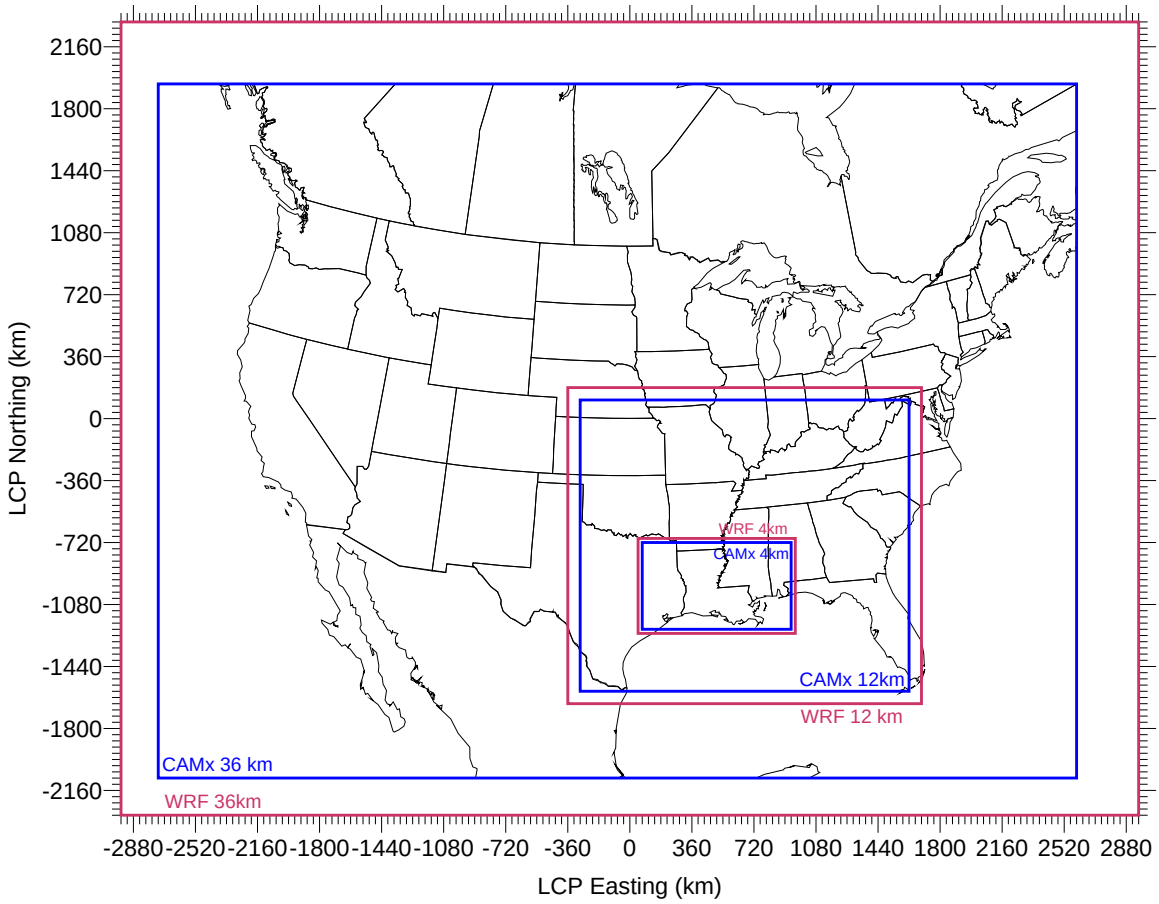
Graphical displays will include daily maximum 8-hour difference plots between the simulations with and without the proposed facility emissions.

Tabular metrics will include:

- Number of grid cell days with increases in maximum simulated 8-hr ozone > 0.2 ppb
- Number of grid cell days with increases in maximum simulated 8-hr ozone > 1.0 ppb
- Number of grid cells with simulated 8-hour ozone concentrations ≥ 75 ppb
- Number of grid cell-hrs with simulated 8-hour ozone concentrations ≥ 75 ppb
- Amount of ozone ≥ 75 ppb summed over all hours and grid cells
- Amount of ozone ≥ 75 ppb squared summed over all hours and grid cells

For the monitor areas; two additional metrics will be used. These include:

- Simulated maximum 8-hour ozone in the vicinity of each monitor for each day
- Simulated average 8-hour ozone in the vicinity of each monitor for each day for the time period that the maximum value occurred.



Louisiana WRF/CAMx Modeling Domains

CAMx
- 36 km: 148 x 112 (-2736, -2088) to (2592, 1944)
- 12 km: 159 x 141 (-288, -1584) to (1620, 108)
- 4 km: 216 x 126 (72, -1224) to (936, -720)

WRF:
- 36 km: 165 x 129 dot points (-2952, -2304) to (2952, 2304)
- 12 km: 172 x 154 dot points (-360, -1656) to (1692, 180)
- 04 km: 229 x 139 dot points (48, -1248) to (960, -696)

Figure 2-1. 36/12/4 km LDEQ 2010 CAMx Domain.

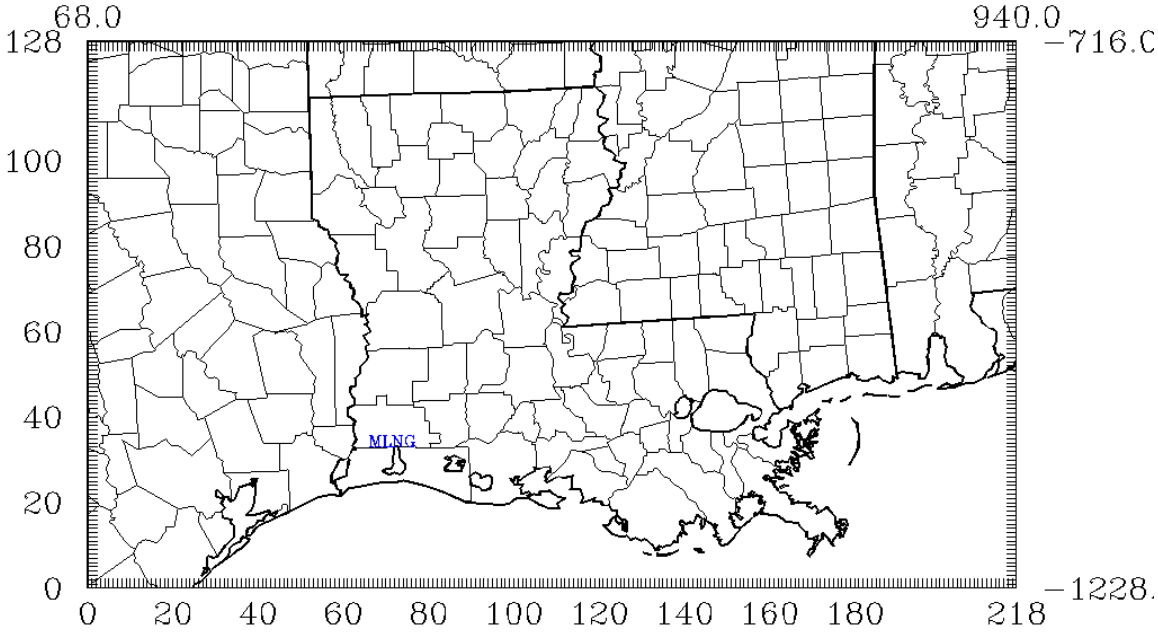


Figure 2-2. Proposed Magnolia LNG Facility Location Within the 4km CAMx Grid.

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Appendix A: Rough Protocol Outline Prepared by USEPA Region 6.

Nucor Ozone Impact Modeling Analysis

An ozone impact analysis can be done using the current CAMx basecase modeling for Baton Rouge (June 2006 episode). Further improvements in the basecase modeling are expected to occur, but the current basecase Run 4 is considered to be performing satisfactorily enough to use for evaluation of potential ozone impacts of the new Nucor facility.

This analysis will be conducted using the June 2006 episode basecase Run 4 modeling outputs and another basecase Run 4 with the proposed additional Nucor emissions (Run 4-N). After the completion of Run 4-N, post-processing of the outputs will be conducted.

Overview of Metrics Used for Impact Assessment

A variety of graphical displays and metrics will be used to assess and quantify the ozone air quality impacts associated with the Nucor related emissions changes. Of primary importance is the impact on modeled values for 8-hour ozone that are near or above the standard. Since the basecase has a slight under-prediction bias and will continue to be improved, we will be slightly conservative and use a 80 ppb threshold instead of 85 ppb. Evaluations will be done for three areas: around existing monitors (Mon), all grid cells in the Baton Rouge NAA (BRNAA), and all grid cells within the greater Baton Rouge MSA (BRMSA). We will also use additional analyses to establish the spatial and temporal distribution and significance of any impacts.

Several metrics will be used to characterize impacts on the three areas (Mon, BRNAA, BRMSA) ozone levels using the 80 ppb threshold. These metrics should be calculated for both the Run 4 and Run 4-N and also the delta between these two runs where appropriate. These include[1]:

- Daily Maximum 8-hour ozone concentration (including daily delta plots-could be included in plots for next metric)
- Number of grid cells with increases in maximum simulated 8-hour ozone > 0.3 ppb and >1 ppb (including daily delta plots for the two cut points)
- 8-hour ozone exceedance exposure metric of ppb*hr, ppb*hr^2 (using decimals)
- Number of grid cells with simulated 8-hour ozone concentrations ≥ 80 ppb
- Number of grid cell-hours with simulated 1-hour ozone concentrations ≥ 80 ppb
- Amount of ozone ≥ 80 ppb summed over all hours and grid cells.

For the Mon area, two additional metrics will be used to characterize impacts in the vicinity of each site. These include:

- Simulated maximum 8-hour ozone in the vicinity[2] of each monitor for each day
- Simulated average 8-hour ozone in the vicinity[2] of each monitor for each day for the same period that the maximum value occurred.

[1] The 0.3 ppb and 1 ppb cut points are not official EPA guidance, but are being used for evaluation purposes. For CAIR and NOx SIP call, EPA used 2 ppb thresholds for entire state impacts.

[2] Defined by the 7 by 7 array of grid cells surrounding each monitoring site, or an approximate 15-km radius of influence.

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Appendix 9.D
Noise Study

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MAGNOLIA LNG PROJECT
Lake Charles, Louisiana

BASELINE NOISE STUDY REPORT

November 2013

Prepared for:

Magnolia LNG, LLC
1001 McKinney, Suite 400
Houston, TX 77002

Prepared by:

ecology and environment, inc.
Global Environmental Specialists

©2013 Ecology and Environment, Inc.

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Photograph 3 8366 Joe Ledoux Road....8

1.0 INTRODUCTION

Magnolia LNG, LLC (Magnolia) is proposing to develop a liquefied natural gas (LNG) facility capable of producing a nominal capacity of approximately 8.0 million metric tonnes per annum (mtpa) of LNG using its highly efficient and patented Optimized Single Mixed Refrigerant (OSMR®) technology. The proposed project is referred to herein as the Magnolia LNG Project, or the Project. The Project would receive natural gas via an existing pipeline that traverses the proposed Project site. The natural gas would be treated, liquefied, and stored on site in two full containment LNG storage tanks with a net pumpable capacity of approximately 160,000 cubic meters (m^3) of LNG each. At full plant capacity, the Project would consist of four LNG trains each with a nominal capacity of 2.0 mtpa of LNG (total nominal capacity of approximately 8.0 mtpa). The LNG would be loaded onto LNG carriers for export overseas; onto LNG carriers and barges for domestic marine distribution and the possibility of LNG bunkering; and onto LNG trucks for road distribution to LNG refueling stations in Louisiana and the surrounding states.

The Project would be located on Industrial Canal South Shore Port of Lake Charles Tract 475, an approximately 115-acre parcel of land in Calcasieu Parish, south of Lake Charles, Louisiana, available through a long-term lease with the Lake Charles Harbor & Terminal District (the Port). The Industrial Canal is located off the main Calcasieu River Ship Channel. The Project would be located in an area zoned for heavy industrial use and would be consistent with other industrial facilities along the shoreline.

This report summarizes the locations, methodology, and noise measurements results for the noise survey conducted by Ecology and Environment, Inc. from September 23 through September 25, 2013. The purpose of the study was to characterize the existing noise environment at the nearest noise sensitive areas (NSAs).

2.0 SOUND FUNDAMENTALS

Noise is defined as any unwanted sound. Sound is defined as any pressure variation that the human ear can detect. Humans can detect a wide range of sound pressures, but only the pressure variations occurring within a particular set of frequencies are experienced as sound. However, the acuity of human hearing is not the same at all frequencies. Humans are less sensitive to low frequencies than to mid-frequencies, so noise measurements are often adjusted (or weighted) to account for human perception and sensitivities. The unit of noise measurement is a decibel (dB). The most common weighting scale used is the A-weighted scale, which was developed to allow sound-level meters to simulate the frequency sensitivity of human hearing. Sound levels measured using this weighting are noted as A-weighted decibels (dBA). ("A" indicates that the sound has been filtered to reduce the strength of very low and very high frequency sounds, much as the human ear does.) The A-weighted scale is logarithmic, so an increase of 10 dB actually represents a sound that is 10 times louder. However, humans do not perceive the 10-dBA increase as 10 times louder, but as only twice as loud.

The following is typical of human responses to changes in noise level:

- A 3-dBA change is the threshold of change detectable by the human ear.
- A 5-dBA change is readily noticeable.
- A 10-dBA change is perceived as a doubling (or halving) of noise level.

Table 2-1 lists typical sources and levels of noise and corresponding human responses to the noise.

Noise sources that affect the environment can be mobile sources such as automobiles, buses, trucks, aircraft, and trains, or stationary sources such as machinery or mechanical equipment associated with industrial and manufacturing operations or building heating, ventilating, and air-conditioning systems. Sources of construction noise are both mobile sources (e.g., trucks, bulldozers, etc.) and stationary sources (e.g., compressors, pile drivers, power tools, etc.).

The sound pressure level (SPL) that humans experience typically varies from moment to moment. Therefore, various descriptors are used to evaluate sound levels over time. Some typical descriptors are defined below.

- L_{eq} is the continuous equivalent sound level. The sound energy from the fluctuating SPLs is averaged over time to create a single number to describe the mean energy, or intensity, level. The duration of the measurement would be shown as $L_{eq}(n)$. A 24-hour measurement would be shown as $L_{eq}(24)$. The L_{eq} has an advantage over other descriptors because L_{eq} values from various sound sources can be combined to determine cumulative sound levels.
- LA_{eq} is the A-weighted L_{eq} value.
- L_n is the SPL exceeded for n percent of the time. In other words, for n percent of the time, the fluctuating SPLs are higher than the L_n level. L_n can be obtained by analyzing a given noise by statistical means. L_{50} is the level exceeded for 50 percent of the time.
- L_{dn} is equivalent to a 24-hour L_{eq}, but with a 10-dBA penalty added to nighttime noise levels (10:00 p.m. to 7:00 a.m.) to reflect the greater intrusiveness of noise experienced during this time.

Table 1 Decibel Level of Some Common Sounds

Sound Source	dB(A)	Perception/Response
	150	
Carrier Deck Jet Operation	140	
	130	Painfully Loud Limit
Jet Takeoff (200 feet) Discotheque	120	
Auto Horn (3 feet) Riveting Machine	110	
Jet Takeoff (2,000 feet) shout (0.5 feet)	100	
N.Y. Subway Station Heavy Truck (50 feet)	90	Very Annoying Hearing Damage (8 hours, continuous exposure)
Pneumatic Drill (50 feet)	80	Annoying
Freight Train (50 feet) Freeway Traffic (50 feet)	70	Telephone Use Difficult Intrusive
Air Conditioning Unit (20 feet)	60	
Light Auto Traffic (50 feet)	50	Quiet
Living Room Bedroom	40	
Library Soft Whisper (15 feet)	30	Very Quiet
Broadcasting Studio	20	
	10	Just Audible
	0	Threshold of Hearing

Source: New York State Department of Environmental Conservation 2001

3.0 EXISTING AMBIENT NOISE

Ambient baseline, or background, sound levels are a function of such things as local traffic, farm machinery, barking dogs, birds, insects, lawnmowers, children playing, and the interaction of the wind with ground cover, buildings, trees, shrubs, power lines, etc. The sound levels vary with time of day, wind speed and direction, and the level of human activity.

4.0 METHODOLOGY

Continuous long-term sound levels were measured statistically in consecutive 1-hour intervals at three noise sensitive property locations in the area. Three Rion NL series ANSI Type I integrating sound level meters were used to carry out the survey. Each of these instruments is intended for use as a long-term environmental sound level data logging instrument measuring the A-weighted sound level. All of the meters were set to continuously record a number of statistical parameters in consecutive 1-hour intervals, including the average $LA_{eq,}$ L_{10}, and L_{50} sound levels. The survey period began on September 23, 2013, and continued over three days, until September 25, 2013.

The microphones used in the survey were protected from rain and self-induced wind noise by high-density foam windscreens designed for long-term outdoor service. In order to further minimize self-induced wind noise, all microphones were located at approximately 1 meter above local grade. Wind speed is a function of elevation and rapidly diminishes near the ground.

The Project site is located in a mixed industrial and rural area with no residents within 0.5 mile of the site and approximately 30 residences within a 1-mile radius of the site. The noise sources in the area include wind, birds, insects, distant industrial facilities, boat traffic, and vehicular traffic on local roads. The nearest NSA (NSA #1) is a residence located about 3,820 feet south of the center of the proposed LNG liquefaction trains.

Sound level measurements were collected at the nearest NSAs to the Project site identified as follows:

- NSA #1 West end of Private Drive off Big Lake Road, north of Airhart Road;
- NSA #2 East end of Private Drive off Big Lake Road, north of Airhart Road; and
- NSA #3 8366 Joe Ledoux Road.

The locations of the noise measurement stations can be seen on Figure 1 and in Photographs 1, 2, and 3.

Weather Conditions

Meteorological conditions during the measurements included clear to partly cloudy skies, northwest winds of 3 to 7 miles per hour and temperatures from 66 to 93 degrees Fahrenheit.

Document Path: C:\VPN_WORK\active_projects\Magnolia_LNG\maps\mxds\mxd_noise_study\Nearest NSA Locations.mxd



Figure 1
Ambient Noise Measurement Locations

Magnolia LNG
Calcasieu Parish, Louisiana

Legend

Proposed LNG Facility Boundary

Ambient Noise Measurement Locations

N
W E
S

0 1,000 2,000 Feet

1:12,000

MAGNOLIA LNG

Source- ESRI 2011-2012

Date: 11/20/2013

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Photograph 1 - West end of Private Drive off Big Lake Road, north of Airhart Road



Photograph 2 - East end of Private Drive off Big Lake Road, north of Airhart Road



Photograph 3 - 8366 Joe Ledoux Road



5.0 RESULTS

Figures 2 through 4 show the hourly average LA_{eq} sound level measured at NSAs #1, #2, and #3, respectively, over the three-day period.

The Ldn for each NSA was calculated using the measured LA_{eq}s in the following formula:

$$Ldn = 10\log10 \quad 1/24 \left[15 \times 10^{(\text{Average Leq Day}/10)} + 9 \times 10^{(\text{Average Leq Night}+10)/10}\right]$$

A summary of the existing noise levels is provided in Table 2.

Table 2 Existing Noise Level Summary for the Project Area

NSA	Distance from NSA (feet)	Direction from NSA	Average Daytime L_{eq} (dBA)	Average Nighttime L_{eq}(dBA)	Calculated L_{dn} (dBA)
#1	3,820	North	46.9	43.8	50.8
#2	4,485	Northwest	48.7	44.8	52.0
#3	7,075	Northwest	43.6	40.2	47.3

6.0 REFERENCES

New York State Department of Environmental Conservation. June 3, 2001 (rev.). Program Policy DEP-00-1, *Assessing and Mitigating Noise Impacts.*

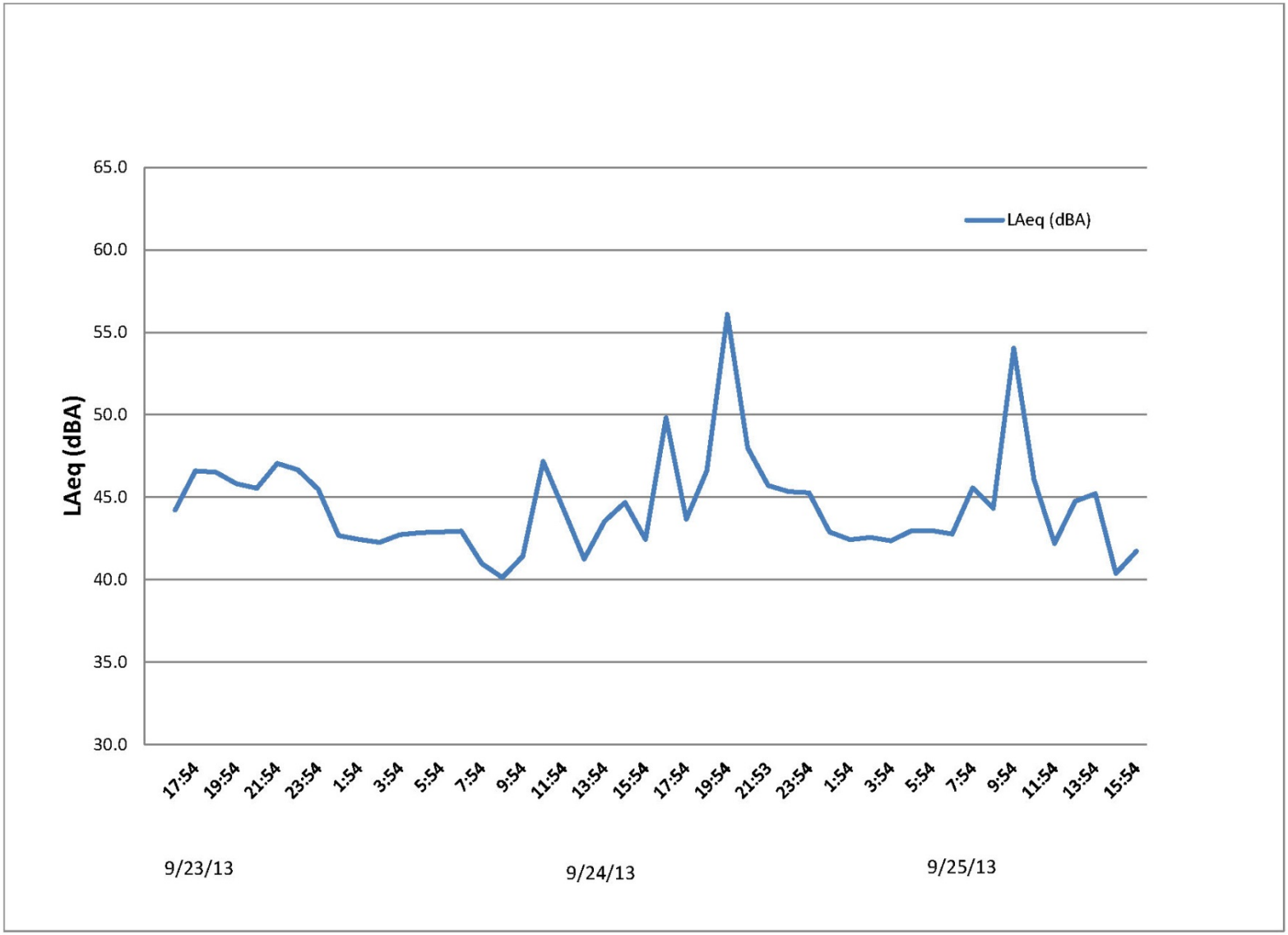


Figure 2 Hourly LAeq Noise Level (dBA) – Receptor 1

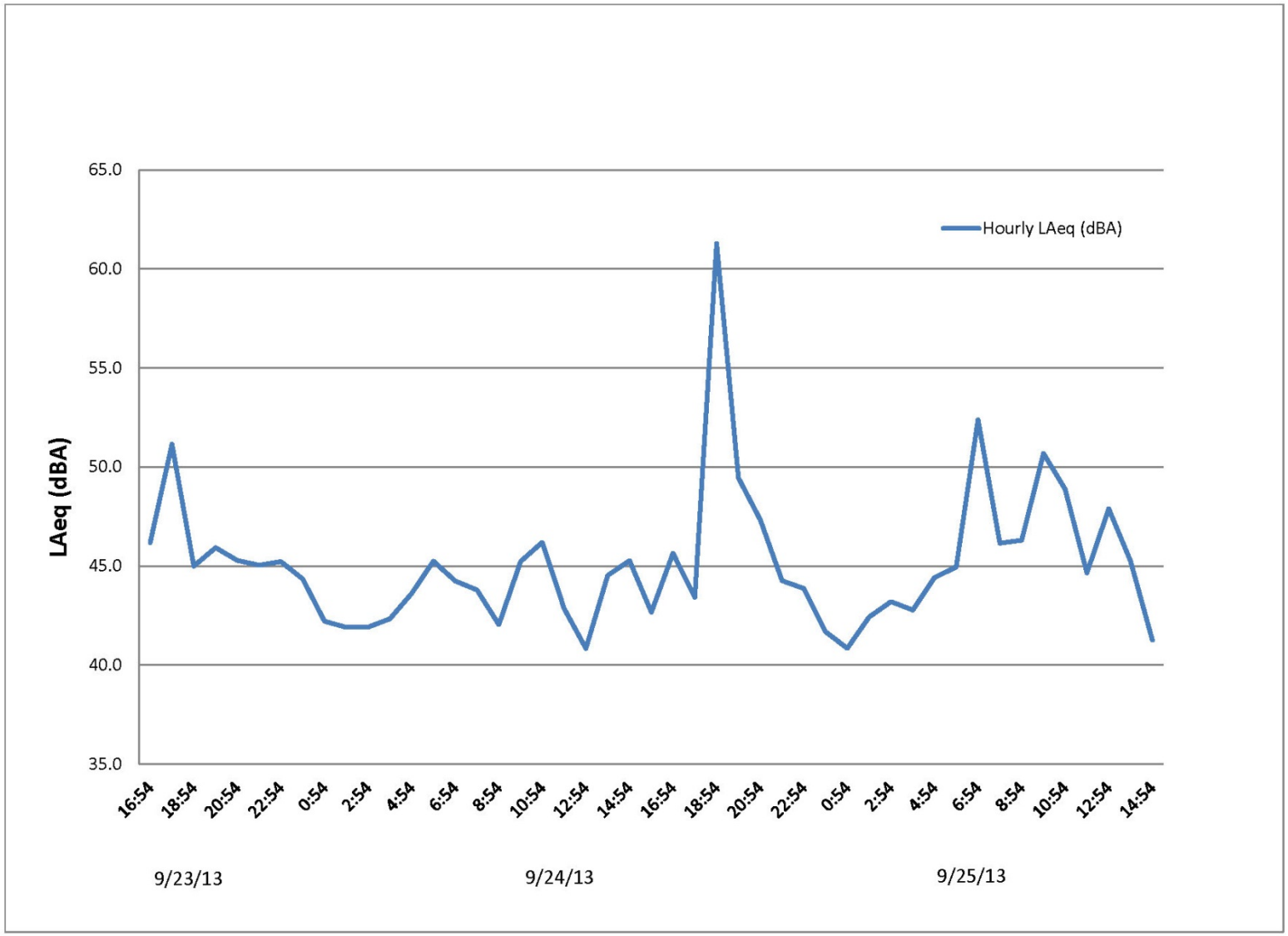


Figure 3 Hourly LAeq Noise Level (dBA) – Receptor 2

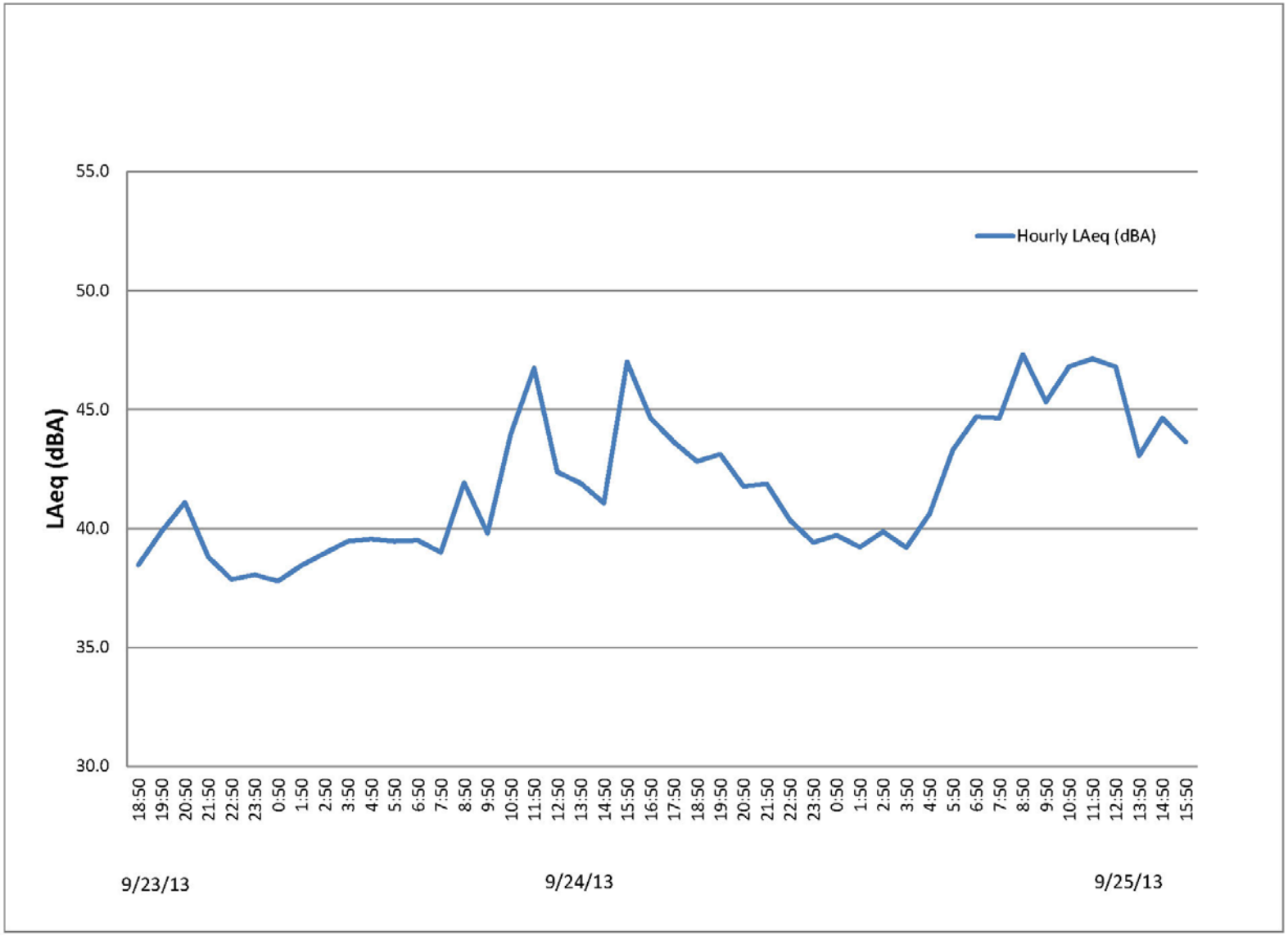


Figure 4 Hourly LAeq Noise Level (dBA) – Receptor 3

Appendix 9.E
Air Permit Application

[Pending LDEQ Review]

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Regulatory Impact Analysis

Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

July 2011

CONTACT INFORMATION

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1 EXECUTIVE SUMMARY

1.1 Background

The U.S. Environmental Protection Agency (EPA) reviewed the New Source Performance Standards (NSPS) for volatile organic compound and sulfur dioxide emissions from Natural Gas Processing Plants. As a result of these NSPS, this proposal amends the Crude Oil and Natural Gas Production source category currently listed under section 111 of the Clean Air Act to include Natural Gas Transmission and Distribution, amends the existing NSPS for volatile organic compounds (VOCs) from Natural Gas Processing Plants, and proposes NSPS for stationary sources in the source categories that are not covered by the existing NSPS. In addition, this proposal addresses the residual risk and technology review conducted for two source categories in the Oil and Natural Gas sector regulated by separate National Emission Standards for Hazardous Air Pollutants (NESHAP). It also proposes standards for emission sources not currently addressed, as well as amendments to improve aspects of these NESHAP related to applicability and implementation. Finally, it addresses provisions in these NESHAP related to emissions during periods of startup, shutdown, and malfunction.

As part of the regulatory process, EPA is required to develop a regulatory impact analysis (RIA) for rules that have costs or benefits that exceed $100 million. EPA estimates the proposed NSPS will have costs that exceed $100 million, so the Agency has prepared an RIA. Because the NESHAP amendments are being proposed in the same rulemaking package (i.e., same Preamble), we have chosen to present the economic impact analysis for the proposed NESHAP amendments within the same document as the NSPS RIA.

This RIA includes an economic impact analysis and an analysis of human health and climate impacts anticipated from the proposed NSPS and NESHAP amendments. We also estimate potential impacts of the proposed NSPS on the national energy economy using the U.S. Energy Information Administration's National Energy Modeling System (NEMS). The engineering compliance costs are annualized using a 7 percent discount rate. This analysis assumes an analysis year of 2015.

Several proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOCs, a large proportion

of the averted methane emissions can be directed into natural gas production streams and sold. One emissions control option, reduced emissions well completions, also recovers saleable hydrocarbon condensates which would otherwise be lost to the environment. The revenues derived from additional natural gas and condensate recovery are expected to offset the engineering costs of implementing the NSPS in the proposed option. In the economic impact and energy economy analyses for the NSPS, we present results for three regulatory options that include the additional product recovery and the revenues we expect producers to gain from the additional product recovery.

1.2 NSPS Results

For the proposed NSPS, the key results of the RIA follow and are summarized in Table 1-1:

- **Benefits Analysis:** The proposed NSPS is anticipated to prevent significant new emissions, including 37,000 tons of hazardous air pollutants (HAPs), 540,000 tons of VOCs, and 3.4 million tons of methane. While we expect that these avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to HAPs, ozone, and particulate matter (PM), we have determined that quantification of those benefits cannot be accomplished for this rule. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, as well as additional natural gas recovery. The methane emissions reductions associated with the proposed NSPS are likely to result in significant climate co-benefits. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of carbon dioxide (CO_2), 510 tons of nitrogen oxides NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.
- **Engineering Cost Analysis:** EPA estimates the total capital cost of the proposed NSPS will be $740 million. The total annualized engineering costs of the proposed NSPS will be $740 million. When estimated revenues from additional natural gas and condensate recovery are included, the annualized engineering costs of the proposed NSPS are estimated at $-45 million, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf) and condensate price of $70/barrel. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA. The estimated engineering compliance costs that include the product recovery are sensitive to the assumption about the price of the recovered product. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. For example, $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million, given EPA estimates that 180 billion cubic feet of natural gas

will be recovered by implementing the proposed NSPS option. All estimates are in 2008 dollars.

- **Energy System Impacts:** Using the NEMS, when additional natural gas recovery is included, the analysis of energy system impacts for the proposed NSPS shows that domestic natural gas production is likely to increase slightly (about 20 billion cubic feet or 0.1 percent) and average natural gas prices to decrease slightly (about $0.04/Mcf or 0.9 percent at the wellhead for onshore production in the lower 48 states). Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.02/barrel or less than 0.1 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars.
- **Small Entity Analyses:** EPA performed a screening analysis for impacts on small entities by comparing compliance costs to revenues. For the proposed NSPS, we found that there will not be a significant impact on a substantial number of small entities (SISNOSE).
- **Employment Impacts Analysis:** EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, as well as labor associated with new reporting and recordkeeping requirements. We estimate up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NSPS is estimated at 230 full-time-equivalent employees. The annual labor requirement to comply with proposed NSPS is estimated at about 2,400 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

Table 1-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Oil and Natural Gas NSPS Regulatory Options in 2015 (millions of 2008$)[1]

	Option 1: Alternative	Option 2: Proposed[4]	Option 3: Alternative
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$19 million	-$45 million	$77 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	17,000 tons of HAPs[5]	37,000 tons of HAPs[5]	37,000 tons of HAPs[5]
	270,000 tons of VOCs	540,000 tons of VOCs	550,000 tons of VOCs
	1.6 million tons of methane[5]	3.4 million tons of methane[5]	3.4 million tons of methane[5]
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

1.3 NESHAP Amendments Results

For the proposed NESHAP amendments, the key results of the RIA follow and are summarized in Table 1-2:

- **Benefits Analysis:** The proposed NESHAP amendments are anticipated to reduce a significant amount of existing emissions, including 1,400 tons of HAPs, 9,200 tons of VOCs, and 4,900 tons of methane. Results from the residual risk assessment indicate that for existing natural gas transmission and storage, the maximum individual cancer risk decreases from 90-in-a-million before controls to 20-in-a-million after controls with benzene as the primary cancer risk driver. While we expect that these avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to HAPs, ozone, and PM, we have determined that quantification of those benefits cannot be accomplished for this rule. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, and climate effects as well as additional natural gas recovery. The specific control technologies for the proposed NESHAP is anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.
- **Engineering Cost Analysis:** EPA estimates the total capital costs of the proposed NESHAP amendments to be $52 million. Total annualized engineering costs of the proposed NESHAP amendments are estimated to be $16 million. All estimates are in 2008 dollars.
- **Energy System Impacts:** We did not estimate the energy economy impacts of the proposed NESHAP amendments as the expected costs of the rule are not likely to have estimable impacts on the national energy economy.
- **Small Entity Analyses:** EPA performed a screening analysis for impacts on small entities by comparing compliance costs to revenues. For the proposed NESHAP amendments, we found that there will not be a significant impact on a substantial number of small entities (SISNOSE).
- **Employment Impacts Analysis:** EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, as well as labor associated with new reporting and recordkeeping requirements. We estimate up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NESHAP Amendments is estimated at 120 full-time-equivalent employees. The annual labor requirement to comply with proposed NESHAP Amendments is estimated at about 102 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

- **Break-Even Analysis:** A break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health benefits, ecosystem and climate co-benefits from the reductions in VOC and methane emissions are assumed to be zero. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the benefits to exceed the costs. Previous assessments have shown that the $PM_{2.5}$ benefits associated with reducing VOC emissions were valued at $280 to $7,000 per ton of VOC emissions reduced in specific urban areas. Previous assessments have shown that the $PM_{2.5}$ benefits associated with reducing VOC emissions were valued at $280 to $7,000 per ton of VOC emissions reduced in specific urban areas, ozone benefits valued at $240 to $1,000 per ton of VOC emissions reduced, and climate co-benefits valued at $110 to $1,400 per short ton of methane reduced. All estimates are in 2008 dollars.

Table 1-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NESHAP in 2015 (millions of 2008$)[1]

	Option 1: Proposed (Floor)
Total Monetized Benefits[2]	N/A
Total Costs[3]	$16 million
Net Benefits	N/A
Non-monetized Benefits	1,400 tons of HAPs
	9,200 tons of VOCs[4]
	4,900 tons of methane[4]
	Health effects of HAP exposure
	Health effects of $PM_{2.5}$ and ozone exposure[4]
	Visibility impairment[4]
	Vegetation effects[4]
	Climate effects[4]

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and PM as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NESHAP are anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] Reduced exposure to VOC emissions, PM2.5 and ozone exposure, visibility and vegetation effects, and climate effects are co-benefits.

1.4 Organization of this Report

The remainder of this report details the methodology and the results of the RIA. Section 2 presents the industry profile of the oil and natural gas industry. Section 3 describes the emissions and engineering cost analysis. Section 4 presents the benefits analysis. Section 5 presents statutory and executive order analyses. Section 6 presents a comparison of benefits and costs. Section 7 presents energy system impact, employment impact, and small business impact analyses.

2 INDUSTRY PROFILE

2.1 Introduction

The oil and natural gas industry includes the following five segments: drilling and extraction, processing, transportation, refining, and marketing. The Oil and Natural Gas NSPS and NESHAP amendments propose controls for the oil and natural gas products and processes of the drilling and extraction of crude oil and natural gas, natural gas processing, and natural gas transportation segments.

Most crude oil and natural gas production facilities are classified under NAICS 211: Crude Petroleum and Natural Gas Extraction (211111) and Natural Gas Liquid Extraction (211112). The drilling of oil and natural gas wells is included in NAICS 213111. Most natural gas transmission and storage facilities are classified under NAICS 486210—Pipeline Transportation of Natural Gas. While other NAICS (213112—Support Activities for Oil and Gas Operations, 221210—Natural Gas Distribution, 486110—Pipeline Transportation of Crude Oil, and 541360—Geophysical Surveying and Mapping Services) are often included in the oil and natural gas sector, these are not discussed in detail in the Industry Profile because they are not directly affected by the proposed NSPS and NESHAP amendments.

The outputs of the oil and natural gas industry are inputs for larger production processes of gas, energy, and petroleum products. As of 2009, the Energy Information Administration (EIA) estimates that about 526,000 producing oil wells and 493,000 producing natural gas wells operated in the United States. Domestic dry natural gas production was 20.5 trillion cubic feet (tcf) in 2009, the highest production level since 1970. The leading five natural gas producing states are Texas, Alaska, Wyoming, Oklahoma, and New Mexico. Domestic crude oil production in 2009 was 1,938 million barrels (bbl). The leading five crude oil producing states are Texas, Alaska, California, Oklahoma, and New Mexico.

The Industry Profile provides a brief introduction to the components of the oil and natural gas industry that are relevant to the proposed NSPS and NESHAP Amendments. The purpose is to give the reader a general understanding of the geophysical, engineering, and economic aspects of the industry that are addressed in subsequent economic analysis in this RIA. The Industry Profile relies heavily on background material from the U.S. EPA's "Economic Analysis of Air

Pollution Regulations: Oil and Natural Gas Production" (1996) and the U.S. EPA's "Sector Notebook Project: Profile of the Oil and Gas Extraction Industry" (2000).

2.2 Products of the Crude Oil and Natural Gas Industry

Each producing crude oil and natural gas field has its own unique properties. The composition of the crude oil and natural gas and reservoir characteristics are likely to be different from that of any other reservoir.

2.2.1 Crude Oil

Crude oil can be broadly classified as paraffinic, naphthenic (or asphalt-based), or intermediate. Generally, paraffinic crudes are used in the manufacture of lube oils and kerosene. Paraffinic crudes have a high concentration of straight chain hydrocarbons and are relatively low in sulfur compounds. Naphthenic crudes are generally used in the manufacture of gasolines and asphalt and have a high concentration of olefin and aromatic hydrocarbons. Naphthenic crudes may contain a high concentration of sulfur compounds. Intermediate crudes are those that are not classified in either of the above categories.

Another classification measure of crude oil and other hydrocarbons is by API gravity. API gravity is a weight per unit volume measure of a hydrocarbon liquid as determined by a method recommended by the American Petroleum Institute (API). A heavy or paraffinic crude oil is typically one with API gravity of 20^{o} or less, while a light or naphthenic crude oil, which typically flows freely at atmospheric conditions, usually has API gravity in the range of the high 30's to the low 40's.

Crude oils recovered in the production phase of the petroleum industry may be referred to as live crudes. Live crudes contain entrained or dissolved gases which may be released during processing or storage. Dead crudes are those that have gone through various separation and storage phases and contain little, if any, entrained or dissolved gases.

2.2.2 Natural Gas

Natural gas is a mixture of hydrocarbons and varying quantities of non-hydrocarbons that exists in a gaseous phase or in solution with crude oil or other hydrocarbon liquids in natural

underground reservoirs. Natural gas may contain contaminants, such as hydrogen sulfide (H_2S), CO_2, mercaptans, and entrained solids.

Natural gas may be classified as wet gas or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons. Dry gas is either natural gas whose water content has been reduced through dehydration or natural gas that contains little or no recoverable liquid hydrocarbons.

Natural gas streams that contain threshold concentrations of H_2S are classified as sour gases. Those with threshold concentrations of CO_2 are classified as acid gases. The process by which these two contaminants are removed from the natural gas stream is called sweetening. The most common sweetening method is amine treating. Sour gas contains a H_2S concentration of greater than 0.25 grain per 100 standard cubic feet, along with the presence of CO_2. Concentrations of H_2S and CO_2, along with organic sulfur compounds, vary widely among sour gases. A majority total onshore natural gas production and nearly all of offshore natural gas production is classified as sweet.

2.2.3 Condensates

Condensates are hydrocarbons in a gaseous state under reservoir conditions, but become liquid in either the wellbore or the production process. Condensates, including volatile oils, typically have an API gravity of 40^o or more. In addition, condensates may include hydrocarbon liquids recovered from gaseous streams from various oil and natural gas production or natural gas transmission and storage processes and operations.

2.2.4 Other Recovered Hydrocarbons

Various hydrocarbons may be recovered through the processing of the extracted hydrocarbon streams. These hydrocarbons include mixed natural gas liquids (NGL), natural gasoline, propane, butane, and liquefied petroleum gas (LPG).

2.2.5 Produced Water

Produced water is the water recovered from a production well. Produced water is separated from the extracted hydrocarbon streams in various production processes and operations.

2.3 Oil and Natural Gas Production Processes

2.3.1 Exploration and Drilling

Exploration involves the search for rock formations associated with oil or natural gas deposits and involves geophysical prospecting and/or exploratory drilling. Well development occurs after exploration has located an economically recoverable field and involves the construction of one or more wells from the beginning (called spudding) to either abandonment if no hydrocarbons are found or to well completion if hydrocarbons are found in sufficient quantities.

After the site of a well has been located, drilling commences. A well bore is created by using a rotary drill to drill into the ground. As the well bore gets deeper sections of drill pipe are added. A mix of fluids called drilling mud is released down into the drill pipe then up the walls of the well bore, which removes drill cuttings by taking them to the surface. The weight of the mud prevents high-pressure reservoir fluids from pushing their way out ("blowing out"). The well bore is cased in with telescoping steel piping during drilling to avoid its collapse and to prevent water infiltration into the well and to prevent crude oil and natural gas from contaminating the water table. The steel pipe is cemented by filling the gap between the steel casing and the wellbore with cement.

Horizontal drilling technology has been available since the 1950s. Horizontal drilling facilitates the construction of horizontal wells by allowing for the well bore to run horizontally underground, increasing the surface area of contact between the reservoir and the well bore so that more oil or natural gas can move into the well. Horizontal wells are particularly useful in unconventional gas extraction where the gas is not concentrated in a reservoir. Recent advances have made it possible to steer the drill in different directions (directional drilling) from the

surface without stopping the drill to switch directions and allowing for a more controlled and precise drilling trajectory.

Hydraulic fracturing (also referred to as "fracking") has been performed since the 1940s (U.S. DOE, 2009). Hydraulic fracturing involves pumping fluids into the well under very high pressures in order to fracture the formation containing the resource. Proppant is a mix of sand and other materials that is pumped down to hold the fractures open to secure gas flow from the formation (U.S. EPA, 2004).

2.3.2 Production

Production is the process of extracting the hydrocarbons and separating the mixture of liquid hydrocarbons, gas, water, and solids, removing the constituents that are non-saleable, and selling the liquid hydrocarbons and gas. The major activities of crude oil and natural gas production are bringing the fluid to the surface, separating the liquid and gas components, and removing impurities.

Oil and natural gas are found in the pores of rocks and sand (Hyne, 2001). In a conventional source, the oil and natural gas have been pushed out of these pores by water and moved until an impermeable surface had been reached. Because the oil and natural gas can travel no further, the liquids and gases accumulate in a reservoir. Where oil and gas are associated, a gas cap forms above the oil. Natural gas is extracted from a well either because it is associated with oil in an oil well or from a pure natural gas reservoir. Once a well has been drilled to reach the reservoir, the oil and gas can be extracted in different ways depending on the well pressure (Hyne, 2001).

Frequently, oil and natural gas are produced from the same reservoir. As wells deplete the reservoirs into which they are drilled, the gas to oil ratio increases (as does the ratio of water to hydrocarbons). This increase of gas over oil occurs because natural gas usually is in the top of the oil formation, while the well usually is drilled into the bottom portion to recover most of the liquid. Production sites often handle crude oil and natural gas from more than one well (Hyne, 2001).

Well pressure is required to move the resource up from the well to the surface. During **primary extraction,** pressure from the well itself drives the resource out of the well directly. Well pressure depletes during this process. Typically, about 30 to 35 percent of the resource in the reservoir is extracted this way (Hyne, 2001). The amount extracted depends on the specific well characteristics (such as permeability and oil viscosity). Lacking enough pressure for the resource to surface, gas or water is injected into the well to increase the well pressure and force the resource out (**secondary** or **improved oil recovery).** Finally, **in tertiary extraction** or **enhanced recovery,** gas, chemicals or steam are injected into the well. This can result in recovering up to 60 percent of the original amount of oil in the reservoir (Hyne, 2001).

In contrast to conventional sources, unconventional oil and gas are trapped in rock or sand or, in the case of oil, are found in rock as a chemical substance that requires a further chemical transformation to become oil (U.S. DOE, 2009). Therefore, the resource does not move into a reservoir as in the case with a conventional source. Mining, induced pressure, or heat is required to release the resource. The specific type of extraction method needed depends on the type of formation where the resource is located. Unconventional natural gas resource types relevant for this proposal include:

- **Shale Natural Gas:** Shale natural gas comes from sediments of clay mixed with organic matter. These sediments form low permeability shale rock formations that do not allow the gas to move. To release the gas, the rock must be fragmented, making the extraction process more complex than it is for conventional gas extraction. Shale gas can be extracted by drilling either vertically or horizontally, and breaking the rock using hydraulic fracturing (U.S. DOE, 2009).

- **Tight Sands Natural Gas:** Reservoirs are composed of low-porosity sandstones and carbonate into which natural gas has migrated from other sources. Extraction of the natural gas from tight gas reservoirs is often performed using horizontal wells. Hydraulic fracturing is often used in tight sands (U.S. DOE, 2009).

- **Coalbed Methane:** Natural gas is present in a coal bed due to the activity of microbes in the coal or from alterations of the coal through temperature changes. Horizontal drilling

is used but given that coalbed methane reservoirs are frequently associated with underground water reservoirs, hydraulic fracturing is often restricted (Andrews, 2009).

2.3.3 Natural Gas Processing

Natural gas conditioning is the process of removing impurities from the gas stream so that it is of sufficient quality to pass through transportation systems and used by final consumers. Conditioning is not always required. Natural gas from some formations emerges from the well sufficiently pure that it can be sent directly to the pipeline. As the natural gas is separated from the liquid components, it may contain impurities that pose potential hazards or other problems.

The most significant impurity is H_2S, which may or may not be contained in natural gas. H_2S is toxic (and potentially fatal at certain concentrations) to humans and is corrosive for pipes. It is therefore desirable to remove H_2S as soon as possible in the conditioning process.

Another concern is that posed by water vapor. At high pressures, water can react with components in the gas to form gas hydrates, which are solids that can clog pipes, valves, and gauges, especially at cold temperatures (Manning and Thompson, 1991). Nitrogen and other gases may also be mixed with the natural gas in the subsurface. These other gases must be separated from the methane prior to sale. High vapor pressure hydrocarbons that are liquids at surface temperature and pressure (benzene, toluene, ethylbenzene, and xylene, or BTEX) are removed and processed separately.

Dehydration removes water from the gas stream. Three main approaches toward dehydration are the use of a liquid or solid desiccant, and refrigeration. When using a liquid desiccant, the gas is exposed to a glycol that absorbs the water. The water can be evaporated from the glycol by a process called heat regeneration. The glycol can then be reused. Solid desiccants, often materials called molecular sieves, are crystals with high surface areas that attract the water molecules. The solids can be regenerated simply by heating them above the boiling point of water. Finally, particularly for gas extracted from deep, hot wells, simply cooling the gas to a temperature below the condensation point of water can remove enough water to transport the gas. Of the three approaches mentioned above, glycol dehydration is the most common when processing at or near the well.

Sweetening is the procedure in which H_2S and sometimes CO_2 are removed from the gas stream. The most common method is amine treatment. In this process, the gas stream is exposed to an amine solution, which will react with the H_2S and separate them from the natural gas. The contaminant gas solution is then heated, thereby separating the gases and regenerating the amine. The sulfur gas may be disposed of by flaring, incinerating, or when a market exists, sending it to a sulfur-recovery facility to generate elemental sulfur as a salable product.

2.3.4 Natural Gas Transmission and Distribution

After processing, natural gas enters a network of compressor stations, high-pressure transmission pipelines, and often-underground storage sites. Compressor stations are any facility which supplies energy to move natural gas at increased pressure in transmission pipelines or into underground storage. Typically, compressor stations are located at intervals along a transmission pipeline to maintain desired pressure for natural gas transport. These stations will use either large internal combustion engines or gas turbines as prime movers to provide the necessary horsepower to maintain system pressure. Underground storage facilities are subsurface facilities utilized for storing natural gas which has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at underground storage facilities include compression and dehydration.

2.4 Reserves and Markets

Crude oil and natural gas have historically served two separate and distinct markets. Oil is an international commodity, transported and consumed throughout the world. Natural gas, on the other hand, has historically been consumed close to where it is produced. However, as pipeline infrastructure and LNG trade expand, natural gas is increasingly a national and international commodity. The following subsections provide historical and forecast data on the U.S. reserves, production, consumption, and foreign trade of crude oil and natural gas.

2.4.1 Domestic Proved Reserves

Table 2-1 shows crude oil and natural gas proved reserves, inferred reserves, and undiscovered and total technically recoverable resources as of 2007. According to EIA[1], these concepts are defined as:

- **Proved reserves:** estimated quantities of energy sources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.

- **Inferred reserves:** the estimate of total volume recovery from known crude oil or natural gas reservoirs or aggregation of such reservoirs is expected to increase during the time between discovery and permanent abandonment.

- **Technically recoverable:** resources that are producible using current technology without reference to the economic viability of production.

The sum of proved reserves, inferred reserves, and undiscovered technically recoverable resources equal the total technically recoverable resources. As seen in Table 2-1, as of 2007, proved domestic crude oil reserves accounted for about 12 percent of the totally technically recoverable crude oil resources.

[1] U.S. Department of Energy, Energy Information Administration, Glossary of Terms <http://www.eia.doe.gov/glossary/index.cfm?id=P> Accessed 12/21/2010.

Table 2-1 Technically Recoverable Crude Oil and Natural Gas Resource Estimates, 2007

Region	Proved Reserves	Inferred Reserves	Undiscovered Technically Recoverable Resources	Total Technically Recoverable Resources
Crude Oil and Lease Condensate (billion bbl)				
48 States Onshore	14.2	48.3	25.3	87.8
48 States Offshore	4.4	10.3	47.2	61.9
Alaska	4.2	2.1	42.0	48.3
Total U.S.	22.8	60.7	114.5	198.0
Dry Natural Gas (tcf)				
Conventionally Reservoired Fields	194.0	671.3	760.4	1625.7
48 States Onshore Non-Associated Gas	149.0	595.9	144.1	889.0
48 States Offshore Non-Associated Gas	12.4	50.7	233.0	296.0
Associated-Dissolved Gas	20.7		117.2	137.9
Alaska	11.9	24.8	266.1	302.8
Shale Gas and Coalbed Methane	43.7	385	64.2	493.0
Total U.S.	237.7	1056.3	824.6	2118.7

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Inferred reserves for associated-dissolved natural gas are included in "Undiscovered Technically Recoverable Resources." Totals may not sum due to independent rounding.

Proved natural gas reserves accounted for about 11 percent of the totally technically recoverable natural gas resources. Significant proportions of these reserves exist in Alaska and offshore areas.

Table 2-2 and Figure 2-1 show trends in crude oil and natural gas production and reserves from 1990 to 2008. In Table 2-2, proved ultimate recovery equals the sum of cumulative production and proved reserves. While crude oil and natural gas are nonrenewable resources, the table shows that proved ultimate recovery rises over time as new discoveries become economically accessible. Reserves growth and decline is also partly a function of exploration activities, which are correlated with oil and natural gas prices. For example, when oil prices are high there is more of an incentive to use secondary and tertiary recovery, as well as to develop unconventional sources.

Table 2-2 Crude Oil and Natural Gas Cumulative Domestic Production, Proved Reserves, and Proved Ultimate Recovery, 1977-2008

	Crude Oil and Lease Condensate (million bbl)			Dry Natural Gas (bcf)		
Year	Cumulative Production	Proved Reserves	Proved Ultimate Recovery	Cumulative Production	Proved Reserves	Proved Ultimate Recovery
1990	158,175	27,556	185,731	744,546	169,346	913,892
1991	160,882	25,926	186,808	762,244	167,062	929,306
1992	163,507	24,971	188,478	780,084	165,015	945,099
1993	166,006	24,149	190,155	798,179	162,415	960,594
1994	168,438	23,604	192,042	817,000	163,837	980,837
1995	170,832	23,548	194,380	835,599	165,146	1,000,745
1996	173,198	23,324	196,522	854,453	166,474	1,020,927
1997	175,553	23,887	199,440	873,355	167,223	1,040,578
1998	177,835	22,370	200,205	892,379	164,041	1,056,420
1999	179,981	23,168	203,149	911,211	167,406	1,078,617
2000	182,112	23,517	205,629	930,393	177,427	1,107,820
2001	184,230	23,844	208,074	950,009	183,460	1,133,469
2002	186,327	24,023	210,350	968,937	186,946	1,155,883
2003	188,400	23,106	211,506	988,036	189,044	1,177,080
2004	190,383	22,592	212,975	1,006,564	192,513	1,199,077
2005	192,273	23,019	215,292	1,024,638	204,385	1,229,023
2006	194,135	22,131	216,266	1,043,114	211,085	1,254,199
2007	196,079	22,812	218,891	1,062,203	237,726	1,299,929
2008	197,987	20,554	218,541	1,082,489	244,656	1,327,145

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**

However, annual production as a percentage of proved reserves has declined over time for both crude oil and natural gas, from above 10 percent in the early 1990s to 8 to 9 percent from 2006 to 2008 for crude oil and from above 11 percent during the 1990s to about 8 percent from 2008 to 2008 for natural gas.

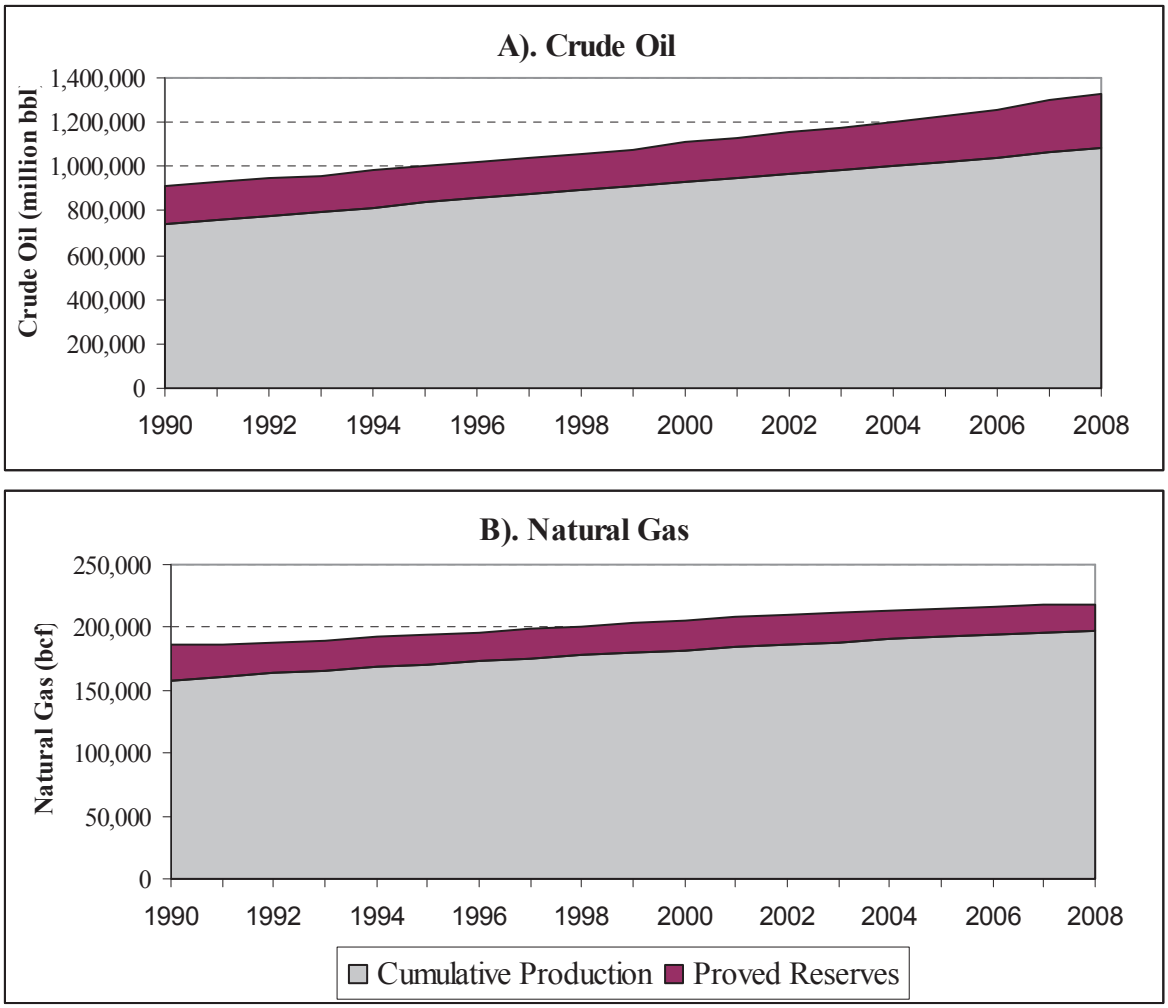


Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2008. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2008

Table 2-3 presents the U.S. proved reserves of crude oil and natural gas by state or producing area as of 2008. Four areas currently account for 77 percent of the U.S. total proved reserves of crude oil, led by Texas and followed by U.S. Federal Offshore, Alaska, and California. The top five states (Texas, Wyoming, Colorado, Oklahoma, and New Mexico) account for about 69 percent of the U.S. total proved reserves of natural gas.

Table 2-3 Crude Oil and Dry Natural Gas Proved Reserves by State, 2008

State/Region	Crude Oil (million bbls)	Dry Natural Gas (bcf)	Crude Oil (percent of total)	Dry Natural Gas (percent of total)
Alaska	3,507	7,699	18.3	3.1
Alabama	38	3,290	0.2	1.3
Arkansas	30	5,626	0.2	2.3
California	2,705	2,406	14.1	1.0
Colorado	288	23,302	1.5	9.5
Florida	3	1	0.0	0.0
Illinois	54	0	0.3	0.0
Indiana	15	0	0.1	0.0
Kansas	243	3,557	1.3	1.5
Kentucky	17	2,714	0.1	1.1
Louisiana	388	11,573	2.0	4.7
Michigan	48	3,174	0.3	1.3
Mississippi	249	1,030	1.3	0.4
Montana	321	1,000	1.7	0.4
Nebraska	8	0	0.0	0.0
New Mexico	654	16,285	3.4	6.7
New York	0	389	0.0	0.2
North Dakota	573	541	3.0	0.2
Ohio	38	985	0.2	0.4
Oklahoma	581	20,845	3.0	8.5
Pennsylvania	14	3,577	0.1	1.5
Texas	4,555	77,546	23.8	31.7
Utah	286	6,643	1.5	2.7
Virginia	0	2,378	0.0	1.0
West Virginia	23	5,136	0.1	2.1
Wyoming	556	31,143	2.9	12.7
Miscellaneous States	24	270	0.1	0.1
U.S. Federal Offshore	3,903	13,546	20.4	5.5
Total Proved Reserves	**19,121**	**244,656**	100.0	100.0

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Totals may not sum due to independent rounding.

2.4.2 Domestic Production

Domestic oil production is currently in a state of decline that began in 1970. Table 2-4 shows U.S. production in 2009 at 1938 million bbl per year, the highest level since 2004. However, annual domestic production of crude oil has dropped by almost 750 million bbl since 1990.

Table 2-4 Crude Oil Domestic Production, Wells, Well Productivity, and U.S. Average First Purchase Price

Year	Total Production (million bbl)	Producing Wells (1000s)	Avg. Well Productivity (bbl/well)	U.S. Average First Purchase Price/Barrel (2005 dollars)
1990	2,685	602	4,460	27.74
1991	2,707	614	4,409	22.12
1992	2,625	594	4,419	20.89
1993	2,499	584	4,279	18.22
1994	2,431	582	4,178	16.51
1995	2,394	574	4,171	17.93
1996	2,366	574	4,122	22.22
1997	2,355	573	4,110	20.38
1998	2,282	562	4,060	12.71
1999	2,147	546	3,932	17.93
2000	2,131	534	3,990	30.14
2001	2,118	530	3,995	24.09
2002	2,097	529	3,964	24.44
2003	2,073	513	4,042	29.29
2004	1,983	510	3,889	38.00
2005	1,890	498	3,795	50.28
2006	1,862	497	3,747	57.81
2007	1,848	500	3,697	62.63
2008	1,812	526	3,445	86.69
2009	1,938	526	3,685	51.37*

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**

First purchase price represents the average price at the lease or wellhead at which domestic crude is purchased. * 2009 Oil price is preliminary

Average well productivity has also decreased since 1990 (Table 2-4 and Figure 2-2). These production and productivity decreases are in spite of the fact that average first purchase prices have shown a generally increasing trend. The exception to this general trend occurred in 2008 and 2009 when the real price increased up to 86 dollars per barrel and production in 2009 increased to almost 2 million bbl of oil.

Annual production of natural gas from natural gas wells has increased nearly 3000 bcf from the 1990 to 2009 (Table 2-5). Natural gas extracted from crude oil wells (associated natural gas) has remained more or less constant for the last twenty years. Coalbed methane has become a significant component of overall gas withdrawals in recent years.

Table 2-5 Natural Gas Production and Well Productivity, 1990-2009

	Natural Gas Gross Withdrawals (bcf)					Natural Gas Well Productivity	
Year	Natural Gas Wells	Crude Oil Wells	Coalbed Methane Wells	Total	Dry Gas Production*	Producing Wells (no.)	Avg. Productivity per Well (MMcf)
1990	16,054	5,469	NA	21,523	17,810	269,100	59.657
1991	16,018	5,732	NA	21,750	17,698	276,337	57.964
1992	16,165	5,967	NA	22,132	17,840	275,414	58.693
1993	16,691	6,035	NA	22,726	18,095	282,152	59.157
1994	17,351	6,230	NA	23,581	18,821	291,773	59.468
1995	17,282	6,462	NA	23,744	18,599	298,541	57.888
1996	17,737	6,376	NA	24,114	18,854	301,811	58.770
1997	17,844	6,369	NA	24,213	18,902	310,971	57.382
1998	17,729	6,380	NA	24,108	19,024	316,929	55.938
1999	17,590	6,233	NA	23,823	18,832	302,421	58.165
2000	17,726	6,448	NA	24,174	19,182	341,678	51.879
2001	18,129	6,371	NA	24,501	19,616	373,304	48.565
2002	17,795	6,146	NA	23,941	18,928	387,772	45.890
2003	17,882	6,237	NA	24,119	19,099	393,327	45.463
2004	17,885	6,084	NA	23,970	18,591	406,147	44.036
2005	17,472	5,985	NA	23,457	18,051	425,887	41.025
2006	17,996	5,539	NA	23,535	18,504	440,516	40.851
2007	17,065	5,818	1,780	24,664	19,266	452,945	37.676
2008	18,011	5,845	1,898	25,754	20,286	478,562	37.636
2009	18,881	5,186	2,110	26,177	20,955	495,697	38.089

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**
*Dry gas production is gas production after accounting for gas used repressurizing wells, the removal of nonhydrocarbon gases, vented and flared gas, and gas used as fuel during the production process.

The number of wells producing natural gas wells has nearly doubled between 1990 and 2009 (Figure 2-2). While the number of producing wells has increased overall, average well productivity has declined, despite improvements in exploration and gas well stimulation technologies.

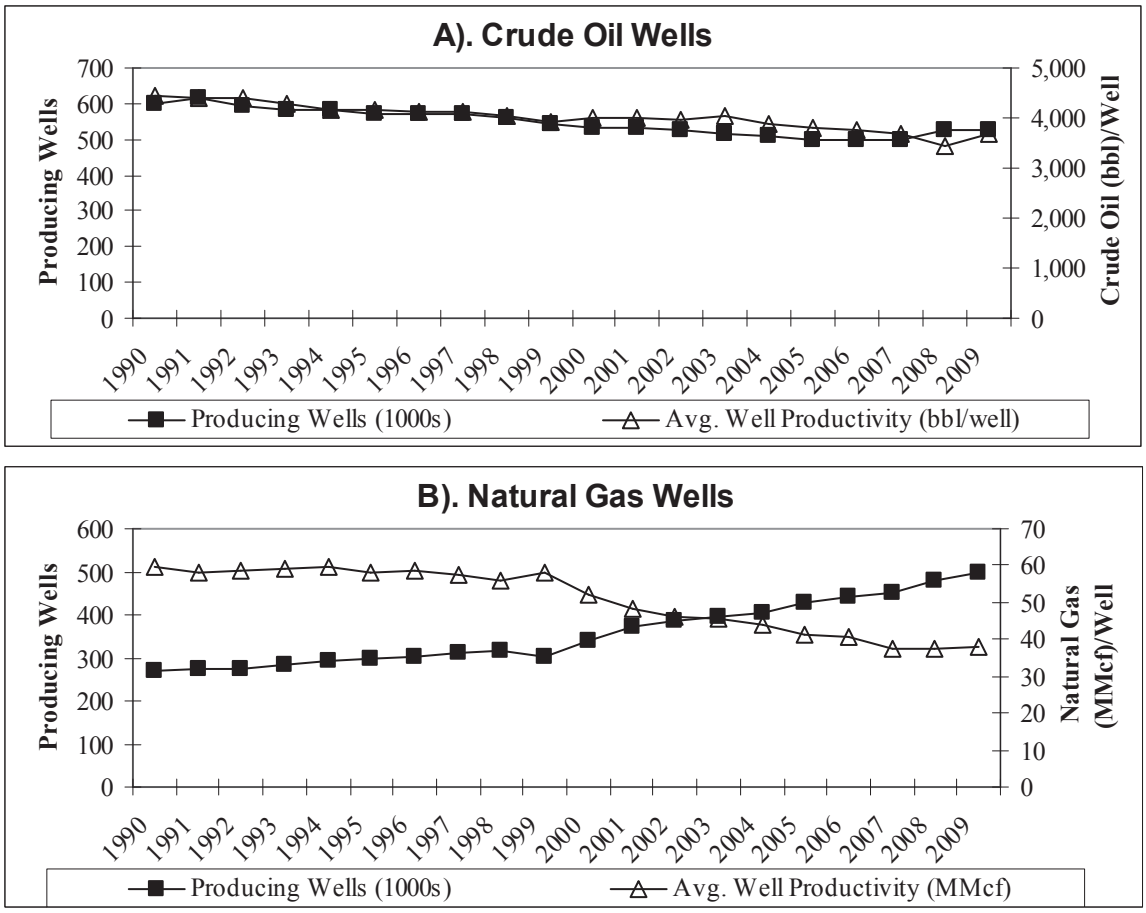


Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2009. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2009.

Domestic exploration and development for oil has continued during the last two decades. From 2002 to 2009, crude oil well drilling showed significant increases, although the 1992-2001 period showed relatively low levels of crude drilling activity compared to periods before and after (Table 2-6). The drop in 2009 showed a departure from this trend, likely due to the recession experienced in the U.S.

Meanwhile, natural gas drilling has increased significantly during the 1990-2009 period. Like crude oil drilling, 2009 saw a relatively low level of natural gas drillings. The success rate of wells (producing wells versus dry wells) has also increased gradually over time from 75 percent in 1990, to 86 percent in 2000, to 90 percent in 2009 (Table 2-6). The increasing success rate reflects improvements in exploration technology, as well as technological improvements in

well drilling and completion. Similarly, well average depth has also increased by during this period (Table 2-6).

Table 2-6 Crude Oil and Natural Gas Exploratory and Development Wells and Average Depth, 1990-2009

	Wells Drilled					
Year	Crude Oil	Natural Gas	Dry Holes	Total	Successful Wells (percent)	Average Depth (ft)
1990	12,800	11,227	8,237	32,264	75	4,841
1991	12,542	9,768	7,476	29,786	75	4,872
1992	9,379	8,149	5,857	23,385	75	5,138
1993	8,828	9,829	6,093	24,750	75	5,407
1994	7,334	9,358	5,092	21,784	77	5,736
1995	8,230	8,081	4,813	21,124	77	5,560
1996	8,819	9,015	4,890	22,724	79	5,573
1997	11,189	11,494	5,874	28,557	79	5,664
1998	7,659	11,613	4,763	24,035	80	5,722
1999	4,759	11,979	3,554	20,292	83	5,070
2000	8,089	16,986	4,134	29,209	86	4,942
2001	8,880	22,033	4,564	35,477	87	5,077
2002	6,762	17,297	3,728	27,787	87	5,223
2003	8,104	20,685	3,970	32,759	88	5,418
2004	8,764	24,112	4,053	36,929	89	5,534
2005E	10,696	28,500	4,656	43,852	89	5,486
2006E	13,289	32,878	5,183	51,350	90	5,537
2007E	13,564	33,132	5,121	51,817	90	5,959
2008E	17,370	34,118	5,726	57,214	90	6,202
2009E	13,175	19,153	3,537	35,865	90	6,108

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Values for 2005-2009 are estimates.

Produced water is an important byproduct of the oil and natural gas industry, as management, including reuse and recycling, of produced water can be costly and challenging. Texas, California, Wyoming, Oklahoma, and Kansas were the top five states in terms of produced water volumes in 2007 (Table 2-7). These estimates do not include estimates of flowback water from hydraulic fracturing activities (ANL 2009).

Table 2-7 U.S. Onshore and Offshore Oil, Gas, and Produced Water Generation, 2007

State	Crude Oil (1000 bbl)	Total Gas (bcf)	Produced Water (1000 bbl)	Total Oil and Natural Gas (1000 bbls oil equivalent)	Barrels Produced Water per Barrel Oil Equivalent
Alabama	5,028	285	119,004	55,758	2.13
Alaska	263,595	3,498	801,336	886,239	0.90
Arizona	43	1	68	221	0.31
Arkansas	6,103	272	166,011	54,519	3.05
California	244,000	312	2,552,194	299,536	8.52
Colorado	2,375	1,288	383,846	231,639	1.66
Florida	2,078	2	50,296	2,434	20.66
Illinois	3,202	no data	136,872	3,202	42.75
Indiana	1,727	4	40,200	2,439	16.48
Kansas	36,612	371	1,244,329	102,650	12.12
Kentucky	3,572	95	24,607	20,482	1.20
Louisiana	52,495	1,382	1,149,643	298,491	3.85
Michigan	5,180	168	114,580	35,084	3.27
Mississippi	20,027	97	330,730	37,293	8.87
Missouri	80	no data	1,613	80	20.16
Montana	34,749	95	182,266	51,659	3.53
Nebraska	2,335	1	49,312	2,513	19.62
Nevada	408	0	6,785	408	16.63
New Mexico	59,138	1,526	665,685	330,766	2.01
New York	378	55	649	10,168	0.06
North Dakota	44,543	71	134,991	57,181	2.36
Ohio	5,422	86	6,940	20,730	0.33
Oklahoma	60,760	1,643	2,195,180	353,214	6.21
Pennsylvania	1,537	172	3,912	32,153	0.12
South Dakota	1,665	12	4,186	3,801	1.10
Tennessee	350	1	2,263	528	4.29
Texas	342,087	6,878	7,376,913	1,566,371	4.71
Utah	19,520	385	148,579	88,050	1.69
Virginia	19	112	1,562	19,955	0.08
West Virginia	679	225	8,337	40,729	0.20
Wyoming	54,052	2,253	2,355,671	455,086	5.18
State Total	***1,273,759***	***21,290***	***20,258,560***	***5,063,379***	***4.00***
Federal Offshore	467,180	2,787	587,353	963,266	0.61
Tribal Lands	9,513	297	149,261	62,379	2.39
Federal Total	***476,693***	***3,084***	***736,614***	***1,025,645***	***0.72***
U.S. Total	**1,750,452**	**24,374**	**20,995,174**	**6,089,024**	**3.45**

Source: Argonne National Laboratory and Department of Energy (2009). Natural gas production converted to barrels oil equivalent to facilitate comparison using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas. Totals may not sum due to independent rounding.

As can be seen in Table 2-7, the amount of water produced is not necessarily correlated with the ratio of water produced to the volume of oil or natural gas produced. Texas, Alaska and Wyoming were the three largest producers in barrels of oil equivalent (boe) terms, but had relatively low rates of water production compared to more Midwestern states, such Illinois, Missouri, Indiana, and Kansas.

Figure 2-3 shows the distribution of produced water management practices in 2007.

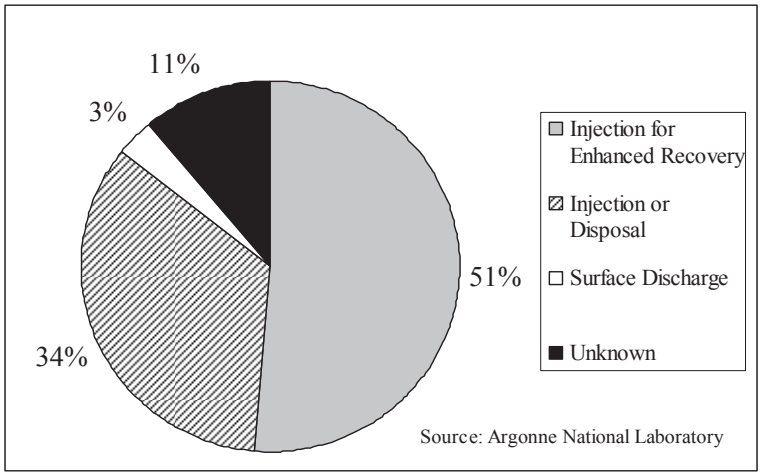


Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007

More than half of the water produced (51 percent) was re-injected to enhance resource recovery through maintaining reservoir pressure or hydraulically pushing oil from the reservoir. Another third (34 percent) was injected, typically into wells whose primary purpose is to sequester produced water. A small percentage (three percent) is discharged into surface water when it meets water quality criteria. The destination of the remaining produced water (11 percent, the difference between the total managed and total generated) is uncertain (ANL, 2009).

The movement of crude oil and natural gas primarily takes place via pipelines. Total crude oil pipeline mileage has decreased during the 1990-2008 period (Table 2-8), appearing to follow the downward supply trend shown in Table 2-4. While exhibiting some variation, pipeline mileage transporting refined products remained relatively constant.

Table 2-8 U.S. Oil and Natural Gas Pipeline Mileage, 1990-2008

	Oil Pipelines			Natural Gas Pipelines			
Year	Crude Lines	Product Lines	Total	Distribution Mains	Transmission Pipelines	Gathering Lines	Total
1990	118,805	89,947	208,752	945,964	291,990	32,420	1,270,374
1991	115,860	87,968	203,828	890,876	293,862	32,713	1,217,451
1992	110,651	85,894	196,545	891,984	291,468	32,629	1,216,081
1993	107,246	86,734	193,980	951,750	293,263	32,056	1,277,069
1994	103,277	87,073	190,350	1,002,669	301,545	31,316	1,335,530
1995	97,029	84,883	181,912	1,003,798	296,947	30,931	1,331,676
1996	92,610	84,925	177,535	992,860	292,186	29,617	1,314,663
1997	91,523	88,350	179,873	1,002,942	294,370	34,463	1,331,775
1998	87,663	90,985	178,648	1,040,765	302,714	29,165	1,372,644
1999	86,369	91,094	177,463	1,035,946	296,114	32,276	1,364,336
2000	85,480	91,516	176,996	1,050,802	298,957	27,561	1,377,320
2001	52,386	85,214	154,877	1,101,485	290,456	21,614	1,413,555
2002	52,854	80,551	149,619	1,136,479	303,541	22,559	1,462,579
2003	50,149	75,565	139,901	1,107,559	301,827	22,758	1,432,144
2004	50,749	76,258	142,200	1,156,863	303,216	24,734	1,484,813
2005	46,234	71,310	131,348	1,160,311	300,663	23,399	1,484,373
2006	47,617	81,103	140,861	1,182,884	300,458	20,420	1,503,762
2007	46,658	85,666	147,235	1,202,135	301,171	19,702	1,523,008
2008	50,214	84,914	146,822	1,204,162	303,331	20,318	1,527,811

Source: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, *Natural Gas Transmission, Gas Distribution, and Hazardous Liquid Pipeline Annual Mileage*, available at http://ops.dot.gov/stats.htm as of Apr. 28, 2010. Totals may not sum due to independent rounding.

Table 2-8 splits natural gas pipelines into three types: distribution mains, transmission pipelines, and gathering lines. Gathering lines are low-volume pipelines that gather natural gas from production sites to deliver directly to gas processing plants or compression stations that connect numerous gathering lines to transport gas primarily to processing plants. Transmission pipelines move large volumes of gas to or from processing plants to distribution points. From these distribution points, the gas enters a distribution system that delivers the gas to final consumers. Table 2-8 shows gathering lines decreasing from 1990 from above 30,000 miles from 1990 to 1995 to around 20,000 miles in 2007 and 2008. Transmission pipelines added

about 10,000 miles during this period, from about 292,000 in 1990 to about 303,000 miles in 2008. The most significant growth among all types of pipeline was in distribution, which increased about 260,000 miles during the 1990 to 2008 period, driving an increase in total natural gas pipeline mileage (Figure 2-1). The growth in distribution is likely driven by expanding production as well as expanding gas markets in growing U.S. towns and cities.

2.4.3 Domestic Consumption

Historical crude oil sector-level consumption trends for 1990 through 2009 are shown in Table 2-9 and Figure 2-4. Total consumption rose gradually until 2008 when consumption dropped as a result of the economic recession. The share of residential, commercial, industrial, and electric power on a percentage basis declined during this period, while the share of total consumption by the transportation sector rose from 64 percent in 1990 to 71 percent in 2009.

Table 2-9 Crude Oil Consumption by Sector, 1990-2009

		Percent of Total				
Year	Total (million bbl)	Residential	Commercial	Industrial	Transportation Sector	Electric Power
1990	6,201	4.4	2.9	25.3	64.1	3.3
1991	6,101	4.4	2.8	25.2	64.4	3.1
1992	6,234	4.4	2.6	26.5	63.9	2.5
1993	6,291	4.5	2.4	25.7	64.5	2.9
1994	6,467	4.3	2.3	26.3	64.4	2.6
1995	6,469	4.2	2.2	25.9	65.8	1.9
1996	6,701	4.4	2.2	26.3	65.1	2.0
1997	6,796	4.2	2.0	26.6	65.0	2.2
1998	6,905	3.8	1.9	25.6	65.7	3.0
1999	7,125	4.2	1.9	25.8	65.4	2.7
2000	7,211	4.4	2.1	24.9	66.0	2.6
2001	7,172	4.3	2.1	24.9	65.8	2.9
2002	7,213	4.1	1.9	25.0	66.8	2.2
2003	7,312	4.2	2.1	24.5	66.5	2.7
2004	7,588	4.0	2.0	25.2	66.2	2.6
2005	7,593	3.9	1.9	24.5	67.1	2.6
2006	7,551	3.3	1.7	25.1	68.5	1.4
2007	7,548	3.4	1.6	24.4	69.1	1.4
2008	7,136	3.7	1.8	23.2	70.3	1.1
2009*	6,820	3.8	1.8	22.5	71.1	0.9

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 consumption is preliminary.

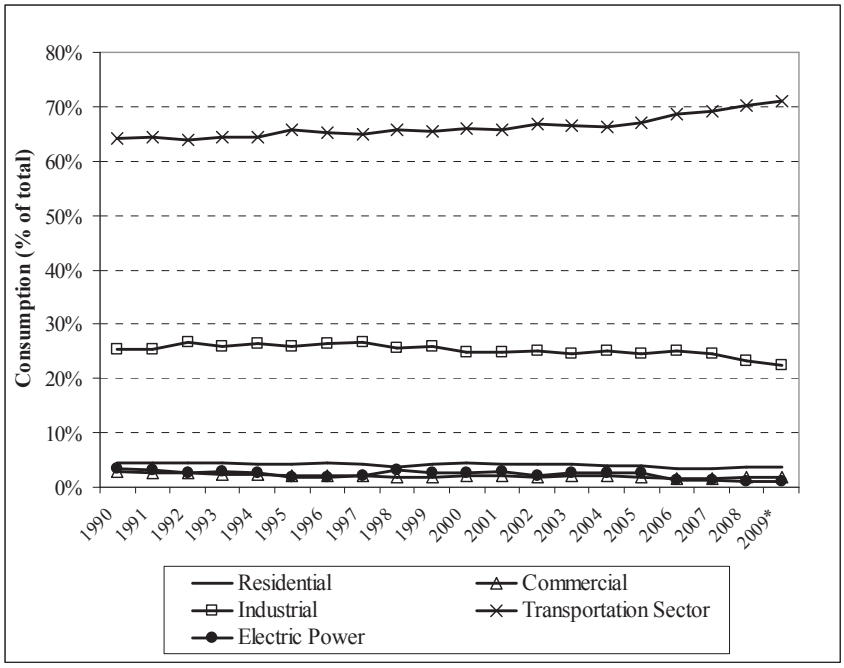


Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2009

Natural gas consumption has increased over the last twenty years. From 1990 to 2009, total U.S. consumption increased by an average of about 1 percent per year (Table 2-10 and Figure 2-5). Over the same period, industrial consumption of natural gas declined, whereas electric power generation increased its consumption quite dramatically, an important trend in the industry as many utilities increasingly use natural gas for peak generation or switch from coal-based to natural gas-based electricity generation. The residential, commercial, and transportation sectors maintained their consumption levels at more or less constant levels during this time period.

Table 2-10 Natural Gas Consumption by Sector, 1990-2009

Year	Total (bcf)	Percent of Total				
		Residential	Commercial	Industrial	Transportation Sector	Electric Power
1990	19,174	22.9	13.7	43.1	3.4	16.9
1991	19,562	23.3	13.9	42.7	3.1	17.0
1992	20,228	23.2	13.9	43.0	2.9	17.0
1993	20,790	23.8	13.8	42.7	3.0	16.7
1994	21,247	22.8	13.6	42.0	3.2	18.4
1995	22,207	21.8	13.6	42.3	3.2	19.1
1996	22,609	23.2	14.0	42.8	3.2	16.8
1997	22,737	21.9	14.1	42.7	3.3	17.9
1998	22,246	20.3	13.5	42.7	2.9	20.6
1999	22,405	21.1	13.6	40.9	2.9	21.5
2000	23,333	21.4	13.6	39.8	2.8	22.3
2001	22,239	21.5	13.6	38.1	2.9	24.0
2002	23,007	21.2	13.7	37.5	3.0	24.7
2003	22,277	22.8	14.3	37.1	2.7	23.1
2004	22,389	21.7	14.0	37.3	2.6	24.4
2005	22,011	21.9	13.6	35.0	2.8	26.7
2006	21,685	20.1	13.1	35.3	2.8	28.7
2007	23,097	20.4	13.0	34.1	2.8	29.6
2008	23,227	21.0	13.5	33.9	2.9	28.7
2009*	22,834	20.8	13.6	32.4	2.9	30.2

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 consumption is preliminary. Totals may not sum due to independent rounding.

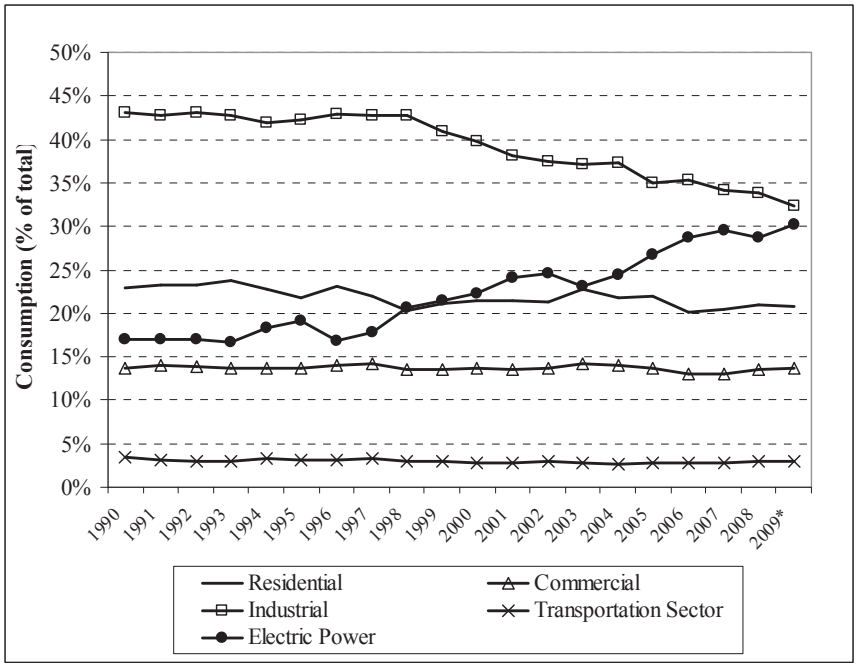


Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2009

2.4.4 International Trade

Imports of crude oil and refined petroleum products have increased over the last twenty years, showing increased substitution of imports for domestic production, as well as imports satisfying growing consumer demand in the U.S (Table 2-11). Crude oil imports have increased by about 2 percent per year on average, whereas petroleum products have increased by 1 percent on average per year.

Table 2-11 Total Crude Oil and Petroleum Products Imports (Million Bbl), 1990-2009

Year	Crude Oil	Petroleum Products	Total Petroleum
1990	2,151	775	2,926
1991	2,111	673	2,784
1992	2,226	661	2,887
1993	2,477	669	3,146
1994	2,578	706	3,284
1995	2,639	586	3,225
1996	2,748	721	3,469
1997	3,002	707	3,709
1998	3,178	731	3,908
1999	3,187	774	3,961
2000	3,320	874	4,194
2001	3,405	928	4,333
2002	3,336	872	4,209
2003	3,528	949	4,477
2004	3,692	1,119	4,811
2005	3,696	1,310	5,006
2006	3,693	1,310	5,003
2007	3,661	1,255	4,916
2008	3,581	1,146	4,727
2009	3,307	973	4,280

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** * 2009 Imports are preliminary.

Natural gas imports also increased steadily from 1990 to 2007 in volume and percentage terms (Table 2-12). The years 2007 and 2008 saw imported natural gas constituting a lower percentage of domestic natural gas consumption. In 2009, the U.S exported 700 bcf natural gas to Canada, 338 bcf to Mexico via pipeline, and 33 bcf to Japan in LNG-form. In 2009, the U.S. primarily imported natural gas from Canada (3268 bcf, 87 percent) via pipeline, although a growing percentage of natural gas imports are in LNG-form shipped from countries such as Trinidad and Tobago and Egypt. Until recent years, industry analysts forecast that LNG imports would continue to grow as a percentage of U.S consumption. However, it is possible that increasingly accessible domestic unconventional gas resources, such as shale gas and coalbed methane, might reduce the need for the U.S. to import natural gas, either via pipeline or shipped LNG.

Table 2-12 Natural Gas Imports and Exports, 1990-2009

Year	Total Imports (bcf)	Total Exports (bcf)	Net Imports (bcf)	Percent of U.S. Consumption
1990	1,532	86	1,447	7.5
1991	1,773	129	1,644	8.4
1992	2,138	216	1,921	9.5
1993	2,350	140	2,210	10.6
1994	2,624	162	2,462	11.6
1995	2,841	154	2,687	12.1
1996	2,937	153	2,784	12.3
1997	2,994	157	2,837	12.5
1998	3,152	159	2,993	13.5
1999	3,586	163	3,422	15.3
2000	3,782	244	3,538	15.2
2001	3,977	373	3,604	16.2
2002	4,015	516	3,499	15.2
2003	3,944	680	3,264	14.7
2004	4,259	854	3,404	15.2
2005	4,341	729	3,612	16.4
2006	4,186	724	3,462	16.0
2007	4,608	822	3,785	16.4
2008	3,984	1,006	2,979	12.8
2009*	3,748	1,071	2,677	11.7

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 Imports are preliminary.

2.4.5 Forecasts

In this section, we provide forecasts of well drilling activity and crude oil and natural gas domestic production, imports, and prices. The forecasts are from the 2011 Annual Energy Outlook produced by EIA, the most current forecast information available from EIA. As will be discussed in detail in Section 3, to analyze the impacts of the proposed NSPS on the national energy economy, we use the National Energy Modeling System (NEMS) that was used to produce the 2011 Annual Energy Outlook.

Table 2-13 and Figure 2-6 present forecasts of successful wells drilled in the U.S. from 2010 to 2035. Crude oil well forecasts for the lower 48 states show a rise from 2010 to a peak in 2019, which is followed by a gradual decline until the terminal year in the forecast, totaling a 28 percent decline for the forecast period. The forecast of successful offshore crude oil wells shows a variable but generally increasing trend.

Table 2-13 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

	Lower 48 U.S. States					Offshore		Totals	
Year	Crude Oil	Conventional Natural Gas	Tight Sands	Devonian Shale	Coalbed Methane	Crude Oil	Natural gas	Crude Oil	Natural Gas
2010	12,082	7,302	2,393	4,196	2,426	74	56	12,155	16,373
2011	10,271	7,267	2,441	5,007	1,593	81	73	10,352	16,380
2012	10,456	7,228	2,440	5,852	1,438	80	71	10,536	17,028
2013	10,724	7,407	2,650	6,758	1,564	79	68	10,802	18,447
2014	10,844	7,378	2,659	6,831	1,509	85	87	10,929	18,463
2015	10,941	7,607	2,772	7,022	1,609	84	87	11,025	19,096
2016	11,015	7,789	2,817	7,104	1,633	94	89	11,108	19,431
2017	11,160	7,767	2,829	7,089	1,631	104	100	11,264	19,416
2018	11,210	7,862	2,870	7,128	1,658	112	101	11,323	19,619
2019	11,268	8,022	2,943	7,210	1,722	104	103	11,373	20,000
2020	10,845	8,136	3,140	7,415	2,228	89	81	10,934	21,000
2021	10,849	8,545	3,286	7,621	2,324	91	84	10,940	21,860
2022	10,717	8,871	3,384	7,950	2,361	90	77	10,807	22,642
2023	10,680	9,282	3,558	8,117	2,499	92	96	10,772	23,551
2024	10,371	9,838	3,774	8,379	2,626	87	77	10,458	24,694
2025	10,364	10,200	3,952	8,703	2,623	93	84	10,457	25,562
2026	10,313	10,509	4,057	9,020	2,705	104	103	10,417	26,394
2027	10,103	10,821	4,440	9,430	2,862	99	80	10,202	27,633
2028	9,944	10,995	4,424	9,957	3,185	128	111	10,072	28,672
2029	9,766	10,992	4,429	10,138	3,185	121	127	9,887	28,870
2030	9,570	11,161	4,512	10,539	3,240	127	103	9,697	29,556
2031	9,590	11,427	4,672	10,743	3,314	124	109	9,714	30,265
2032	9,456	11,750	4,930	11,015	3,449	143	95	9,599	31,239
2033	9,445	12,075	5,196	11,339	3,656	116	107	9,562	32,372
2034	9,278	12,457	5,347	11,642	3,669	128	92	9,406	33,206
2035	8,743	13,003	5,705	12,062	3,905	109	108	8,852	34,782

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.**

Meanwhile, Table 2-13 and Figure 2-6 show increases for all types of natural gas drilling in the lower 48 states. Drilling in shale reservoirs is expected to rise most dramatically, about 190 percent during the forecast period, while drilling in coalbed methane and tight sands reservoirs increase significantly, 61 percent and 138 percent, respectively. Despite the growth in drilling in unconventional reservoirs, EIA forecasts successful conventional natural gas wells to increase about 78 percent during this period. Offshore natural gas wells are also expected to increase during the next 25 years, but not to the degree of onshore drilling.

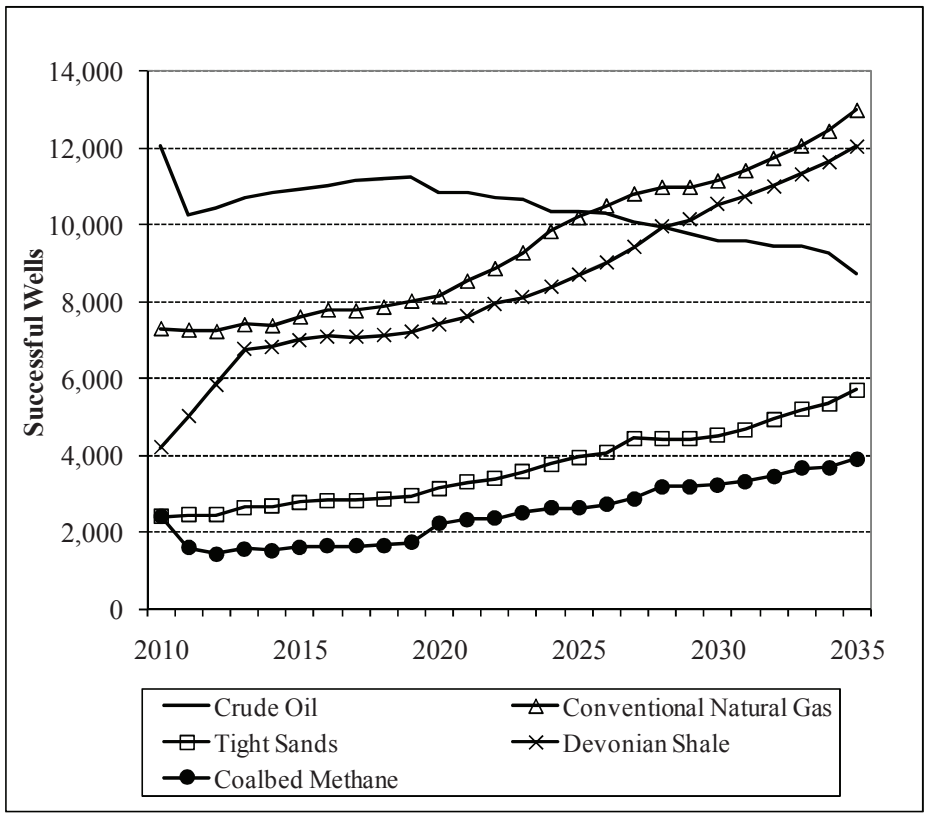


Figure 2-6 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

Table 2-14 presents forecasts of domestic crude oil production, reserves, imports and prices. Domestic crude oil production increases slightly during the forecast period, with much of the growth coming from onshore production in the lower 48 states. Alaskan oil production is forecast to decline from 2010 to a low of 99 million barrels in 2030, but rising above that level for the final five years of the forecast. Net imports of crude oil are forecast to decline slightly during the forecast period. Figure 2-7 depicts these trends graphically. All told, EIA forecasts total crude oil to decrease about 3 percent from 2010 to 2035.

Table 2-14 Forecast of Crude Oil Supply, Reserves, and Wellhead Prices, 2010-2035

	Domestic Production (million bbls)							
Year	Total Domestic	Lower 48 Onshore	Lower 48 Offshore	Alaska	Lower 48 End of Year Reserves	Net Imports	Total Crude Supply (million bbls)	Lower 48 Average Wellhead Price (2009 dollars per bbl)
2010	2,011	1,136	653	223	17,634	3,346	5,361	78.6
2011	1,993	1,212	566	215	17,955	3,331	5,352	84.0
2012	1,962	1,233	529	200	18,026	3,276	5,239	86.2
2013	2,037	1,251	592	194	18,694	3,259	5,296	88.6
2014	2,102	1,267	648	188	19,327	3,199	5,301	92.0
2015	2,122	1,283	660	179	19,690	3,177	5,299	95.0
2016	2,175	1,299	705	171	20,243	3,127	5,302	98.1
2017	2,218	1,320	735	163	20,720	3,075	5,293	101.0
2018	2,228	1,323	750	154	21,129	3,050	5,277	103.7
2019	2,235	1,343	746	147	21,449	3,029	5,264	105.9
2020	2,219	1,358	709	153	21,573	3,031	5,250	107.4
2021	2,216	1,373	680	163	21,730	3,049	5,265	108.8
2022	2,223	1,395	659	169	21,895	3,006	5,229	110.3
2023	2,201	1,418	622	161	21,921	2,994	5,196	112.0
2024	2,170	1,427	588	155	21,871	2,996	5,166	113.6
2025	2,146	1,431	566	149	21,883	3,010	5,155	115.2
2026	2,123	1,425	561	136	21,936	3,024	5,147	116.6
2027	2,114	1,415	573	125	22,032	3,018	5,131	117.8
2028	2,128	1,403	610	116	22,256	2,999	5,127	118.8
2029	2,120	1,399	614	107	22,301	2,988	5,108	119.3
2030	2,122	1,398	625	99	22,308	2,994	5,116	119.5
2031	2,145	1,391	641	114	22,392	2,977	5,122	119.6
2032	2,191	1,380	675	136	22,610	2,939	5,130	118.8
2033	2,208	1,365	691	152	22,637	2,935	5,143	119.1
2034	2,212	1,351	714	147	22,776	2,955	5,167	119.2
2035	2,170	1,330	698	142	22,651	3,007	5,177	119.5

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.** Totals may not sum due to independent rounding.

Table 2-14 also shows forecasts of proved reserves in the lower 48 states. The reserves forecast shows steady growth from 2010 to 2035, an increase of 28 percent overall. This increment is larger than the forecast increase in production from the lower 48 states during this period, 8 percent, showing reserves are forecast to grow more rapidly than production. Table 2-14 also

shows average wellhead prices increasing a total of 52 percent from 2010 to 2035, from $78.6 per barrel to $119.5 per barrel in 2008 dollar terms.

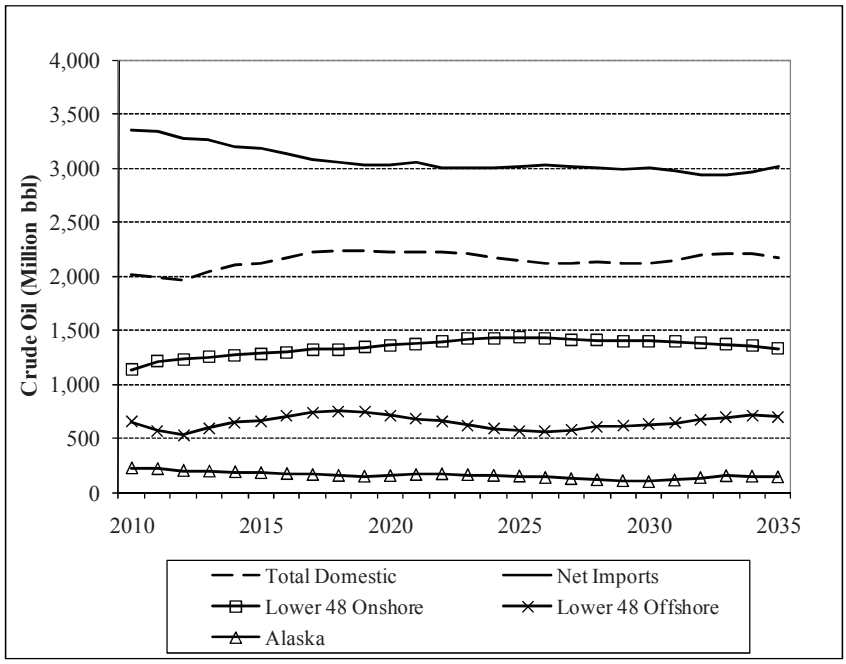


Figure 2-7 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2035

Table 2-15 shows domestic natural gas production is forecast to increase about 24 percent from 2010 to 2035. Contrasted against the much higher growth in natural gas wells drilled as shown in Table 2-13, per well productivity is expected to continue its declining trend. Meanwhile, imports of natural gas via pipeline are expected to decline during the forecast period almost completely, from 2.33 tcf in 2010 to 0.04 in 2035 tcf. Imported LNG also decreases from 0.41 tcf in 2010 to 0.14 tcf in 2035. Total supply, then, increases about 10 percent, from 24.08 tcf in 2010 to 26.57 tcf in 2035.

Table 2-15 Forecast of Natural Gas Supply, Lower 48 Reserves, and Wellhead Price

	Production		Net Imports				
Year	Dry Gas Production	Supplemental Natural Gas	Net Imports (Pipeline)	Net Imports (LNG)	Total Supply	Lower 48 End of Year Dry Reserves	Average Lower 48 Wellhead Price (2009 dollars per Mcf)
2010	21.28	0.07	2.33	0.41	24.08	263.9	4.08
2011	21.05	0.06	2.31	0.44	23.87	266.3	4.09
2012	21.27	0.06	2.17	0.47	23.98	269.1	4.09
2013	21.74	0.06	2.22	0.50	24.52	272.5	4.15
2014	22.03	0.06	2.26	0.45	24.80	276.6	4.16
2015	22.43	0.06	2.32	0.36	25.18	279.4	4.24
2016	22.47	0.06	2.26	0.36	25.16	282.4	4.30
2017	22.66	0.06	2.14	0.41	25.28	286.0	4.33
2018	22.92	0.06	2.00	0.43	25.40	289.2	4.37
2019	23.20	0.06	1.75	0.47	25.48	292.1	4.43
2020	23.43	0.06	1.40	0.50	25.40	293.6	4.59
2021	23.53	0.06	1.08	0.52	25.19	295.1	4.76
2022	23.70	0.06	0.89	0.49	25.14	296.7	4.90
2023	23.85	0.06	0.79	0.45	25.15	297.9	5.08
2024	23.86	0.06	0.77	0.39	25.08	298.4	5.27
2025	23.99	0.06	0.74	0.34	25.12	299.5	5.43
2026	24.06	0.06	0.71	0.27	25.10	300.8	5.54
2027	24.30	0.06	0.69	0.22	25.27	302.1	5.67
2028	24.59	0.06	0.67	0.14	25.47	304.4	5.74
2029	24.85	0.06	0.63	0.14	25.69	306.6	5.78
2030	25.11	0.06	0.63	0.14	25.94	308.5	5.82
2031	25.35	0.06	0.57	0.14	26.13	310.1	5.90
2032	25.57	0.06	0.50	0.14	26.27	311.4	6.01
2033	25.77	0.06	0.38	0.14	26.36	312.6	6.12
2034	26.01	0.06	0.23	0.14	26.44	313.4	6.24
2035	26.33	0.06	0.04	0.14	26.57	314.0	6.42

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.** Totals may not sum due to independent rounding.

2.5 Industry Costs

2.5.1 Finding Costs

Real costs of drilling oil and natural gas wells have increased significantly over the past two decades, particularly in recent years. Cost per well has increased by an annual average of about 15 percent, and cost per foot has increased on average of about 13 percent per year (Figure 2-8).

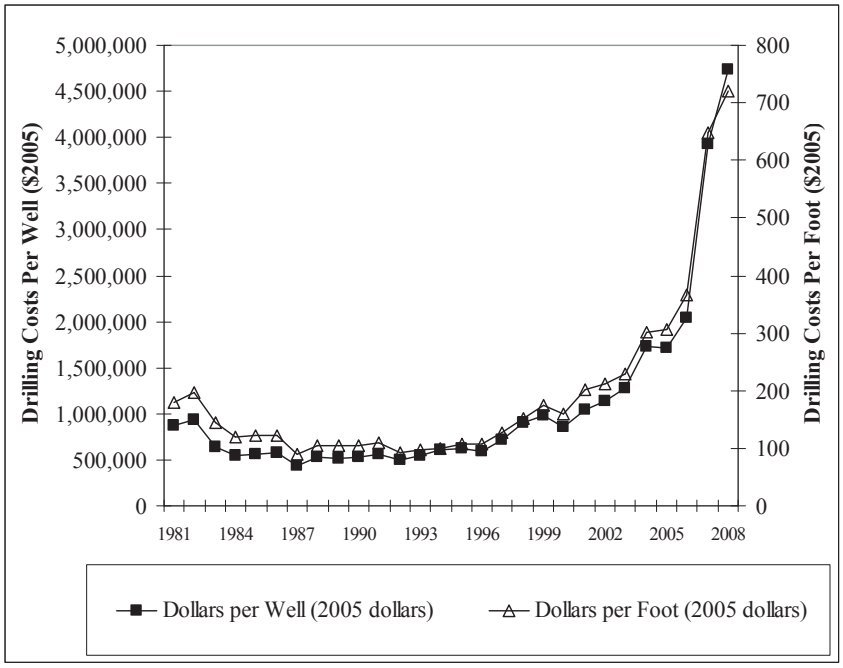


Figure 2-8 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008

The average finding costs compiled and published by EIA add an additional level of detail to drilling costs, in that finding costs incorporate the costs more broadly associated with adding proved reserves of crude oil and natural gas. These costs include exploration and development costs, as well as costs associated with the purchase or leasing of real property. EIA publishes finding costs as running three-year averages, in order to better compare these costs, which occur over several years, with annual average lifting costs. Figure 2-9 shows average domestic onshore and offshore and foreign finding costs for the sample of U.S. firms in EIA's Financial Reporting System (FRS) database from 1981 to 2008. The costs are reported in 2008 dollars on a barrel of oil equivalent basis for crude oil and natural gas combined. The average domestic finding costs dropped from 1981 until the mid-1990s. Interestingly, in the mid-1990s, domestic onshore and offshore and foreign finding costs converged for a few years. After this period, offshore finding costs rose faster than domestic onshore and foreign costs.

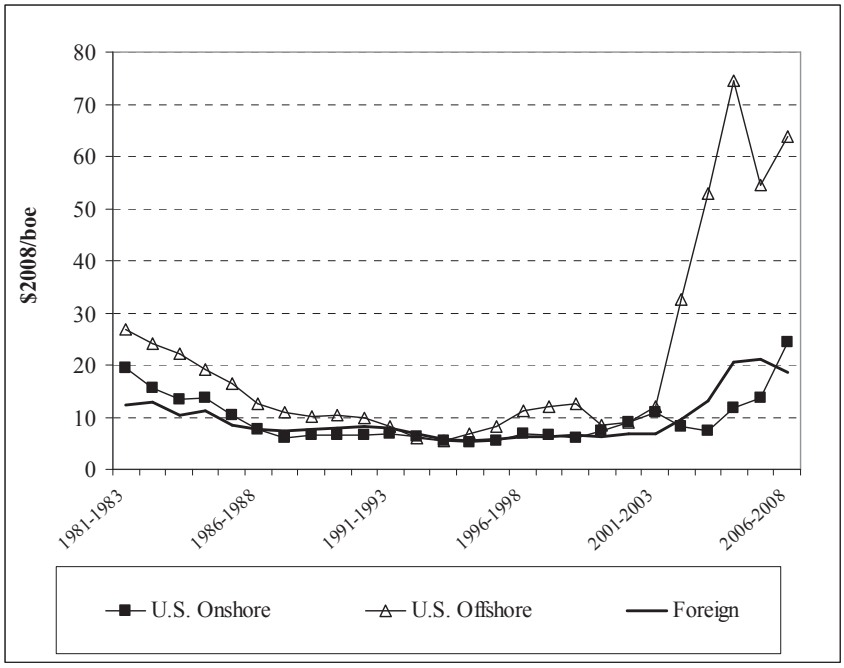


Figure 2-9 Finding Costs for FRS Companies, 1981-2008

After 2000, average finding costs rose sharply, with the finding costs for domestic onshore and offshore and foreign proved reserves diverging onto different trajectories. Note the drilling costs in Figure 2-8 and finding costs in Figure 2-9 present similar trends overall.

2.5.2 Lifting Costs

Lifting costs are the costs to produce crude oil or natural gas once the resource has been found and accessed. EIA's definition of lifting costs includes costs of operating and maintaining wells and associated production equipment. Direct lifting costs exclude production taxes or royalties, while total lifting costs includes taxes and royalties. Like finding costs, EIA reports average lifting costs for FRS firms in 2008 dollars on a barrel of oil equivalent basis. Total lifting costs are the sum of direct lifting costs and production taxes. Figure 2-10 depicts direct lifting cost trends from 1981 to 2008 for domestic and foreign production.

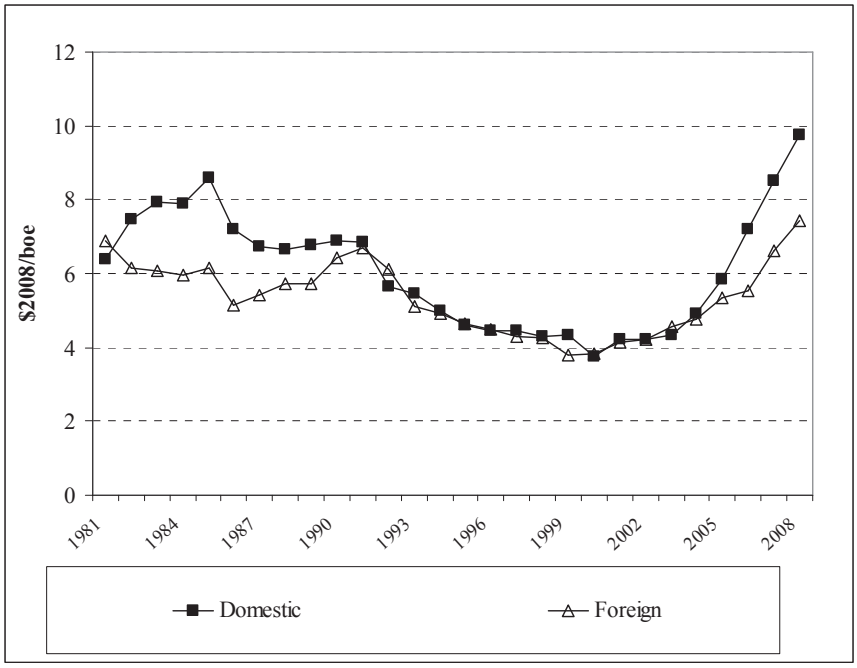


Figure 2-10 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2008 (3-year Running Average)

Direct lifting costs (excludes taxes and royalties) for domestic production rose a little more than $2 per barrels of oil equivalent from 1981 to 1985, then declined almost $5 per barrel of oil equivalent from 1985 until 2000. From 2000 to 2008, domestic lifting costs increased sharply, about $6 per barrel of oil equivalent. Foreign lifting costs diverged from domestic lifting costs from 1981 to 1991, as foreign lifting costs were lower than domestic costs during this period. Foreign and domestic lifting costs followed a similar track until they again diverged in 2004, with domestic lifting again becoming more expensive. Combined with finding costs, the total finding and lifting costs rose significantly in from 2000 to 2008.

2.5.3 Operating and Equipment Costs

The EIA report, "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009"[2], contains indices and estimated costs for domestic oil and natural gas equipment and production operations. The indices and cost trends track costs for representative operations in

[2] U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009." September 28, 2010. <http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed February 2, 2011.

six regions (California, Mid-Continent, South Louisiana, South Texas, West Texas, and Rocky Mountains) with producing depths ranging from 2000 to 16,000 feet and low to high production rates (for example, 50,000 to 1 million cubic feet per day for natural gas).

Figure 2-11 depicts crude oil operating costs and equipment costs indices for 1976 to 2009, as well as the crude oil price in 1976 dollars. The indices show that crude oil operating and equipment costs track the price of oil over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and oil prices rose steeply in the late 1970s, but generally decreased from about 1980 until the late 1990s.

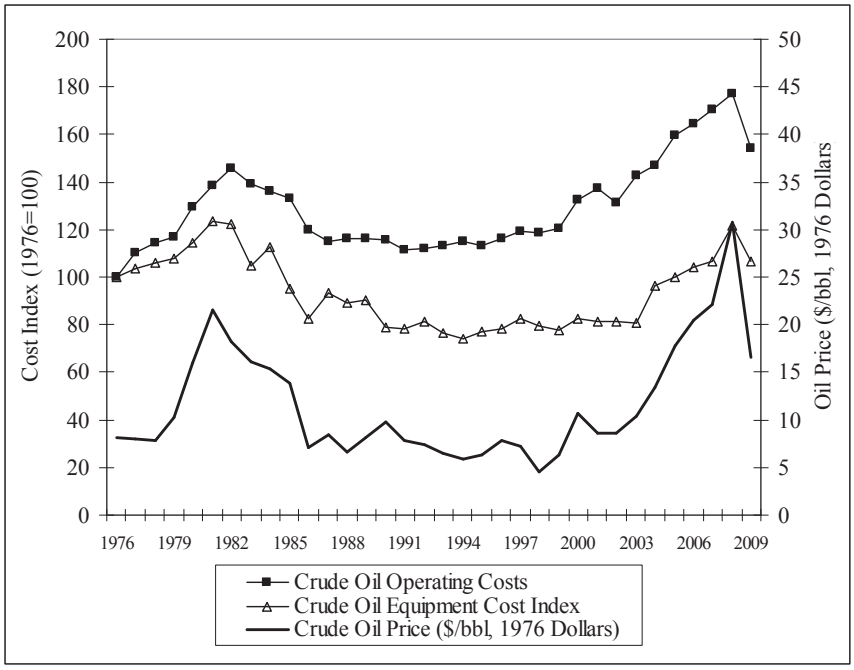


Figure 2-11 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009

Oil costs and prices again generally rose between 2000 to present, with a peak in 2008. The 2009 index values for crude oil operating and equipment costs are 154 and 107, respectively.

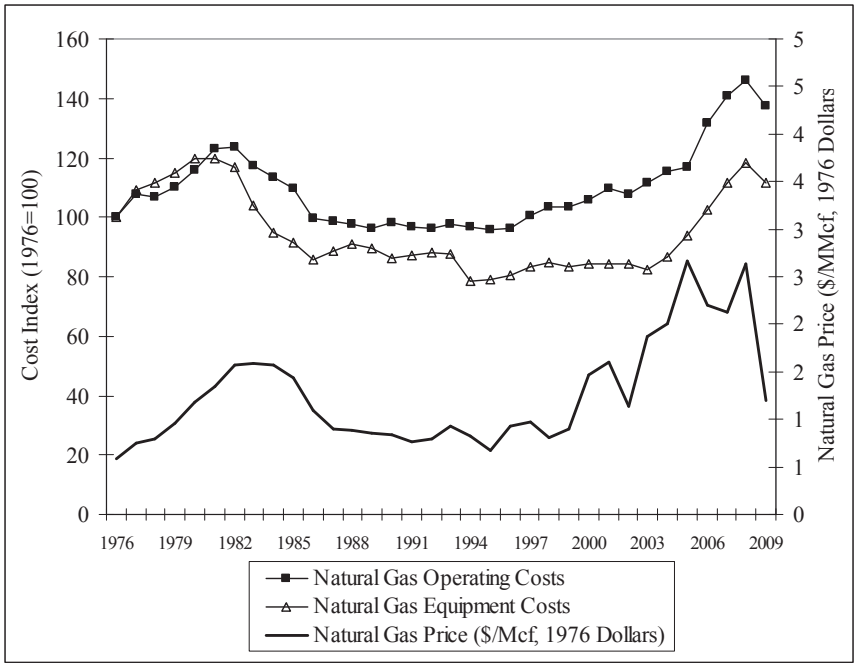


Figure 2-12 Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009

Figure 2-12 depicts natural gas operating and equipment costs indices, as well as natural gas prices. Similar to the cost trends for crude oil, natural gas operating and equipment costs track the price of natural gas over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and gas prices also rose steeply in the late 1970s, but generally decreased from about 1980 until the mid 1990s. The 2009 index values for natural gas operating and equipment costs are 137 and 112, respectively.

2.6 Firm Characteristics

A regulatory action to reduce pollutant discharges from facilities producing crude oil and natural gas will potentially affect the business entities that own the regulated facilities. In the oil and natural gas production industry, facilities comprise those sites where plant and equipment extract, process, and transport extracted streams recovered from the raw crude oil and natural gas resources. Companies that own these facilities are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility.

2.6.1 Ownership

Enterprises in the oil and natural gas industry may be divided into different groups that include producers, transporters, and distributors. The producer segment may be further divided between major and independent producers. Major producers include large oil and gas companies

that are involved in each of the five industry segments: drilling and exploration, production, transportation, refining, and marketing. Independent producers include smaller firms that are involved in some but not all of the five activities.

According to the Independent Petroleum Association of America (IPAA), independent companies produce approximately 68 percent of domestic crude oil production of our oil, 85 percent of domestic natural gas, and drill almost 90 percent of the wells in the U.S (IPAA, 2009). Through the mid-1980s, natural gas was a secondary fuel for many producers. However, now it is of primary importance to many producers. IPAA reports that about 50 percent of its members' spending in 2007 was directed toward natural gas production, largely toward production of unconventional gas (IPAA, 2009). Meanwhile, transporters are comprised of the pipeline companies, while distributors are comprised of the local distribution companies.

2.6.2 Size Distribution of Firms in Affected

As of 2007, there were 6,563 firms within the 211111 and 211112 NAICS codes, of which 6427 (98 percent) were considered small businesses (Table 2-16). Within NAICS 211111 and 211112, large firms compose about 2 percent of the firms, but account for 59 percent of employment and generate about 80 percent of estimated receipts listed under the NAICS.

Table 2-16 SBA Size Standards and Size Distribution of Oil and Natural Gas Firms

NAICS	NAICS Description	SBA Size Standard	Small Firms	Large Firms	Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	98	41	139
213111	Drilling Oil and Gas Wells	500	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	61*	65*	126
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	24,683
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	500	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	20,796,681

Note: *The counts of small and large firms in NAICS 486210 is based upon firms with less than $7.5 million in receipts, rather than the $7 million required by the SBA Size Standard. We used this value because U.S. Census reports firm counts for firms with receipts less than $7.5 million. **Employment and receipts could not be split between small and large businesses because of non-disclosure requirements faced by the U.S. Census Bureau.
Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007." <http://www.census.gov/econ/susb/>

The small and large firms within NAICS 21311 are similarly distributed, with large firms accounting for about 2 percent of firms, but 66 percent and 69 percent of employment and estimated receipts, respectively. Because there are relatively few firms within NAICS 486210, the Census Bureau cannot release breakdowns of firms by size in sufficient detail to perform similar calculation.

2.6.3 Trends in National Employment and Wages

As well as producing much of the U.S. energy supply, the oil and natural gas industry directly employs a significant number of people. Table 2-17 shows employment in oil and natural gas-related NAICS codes from 1990 to 2009. The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of 313,703 in 1999, but rebounding to a 2008 peak of 511,805. Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Support Activities for Oil and Gas Operations (NAICS 213112) employ the majority of workers in the industry.

Table 2-17 Oil and Natural Gas Industry Employment by NAICS, 1990-09

Year	Crude Petroleum and Natural Gas Extraction (211111)	Natural Gas Liquid Extraction (211112)	Drilling of Oil and Natural Gas Wells (213111)	Support Activities for Oil and Gas Ops. (213112)	Pipeline Trans. of Crude Oil (486110)	Pipeline Trans. of Natural Gas (486210)	Total
1990	182,848	8,260	52,365	109,497	11,112	47,533	411,615
1991	177,803	8,443	46,466	116,170	11,822	48,643	409,347
1992	169,615	8,819	39,900	99,924	11,656	46,226	376,140
1993	159,219	7,799	42,485	102,840	11,264	43,351	366,958
1994	150,598	7,373	44,014	105,304	10,342	41,931	359,562
1995	142,971	6,845	43,114	104,178	9,703	40,486	347,297
1996	139,016	6,654	46,150	107,889	9,231	37,519	346,459
1997	137,667	6,644	55,248	117,460	9,097	35,698	361,814
1998	133,137	6,379	53,943	122,942	8,494	33,861	358,756
1999	124,296	5,474	41,868	101,694	7,761	32,610	313,703
2000	117,175	5,091	52,207	108,087	7,657	32,374	322,591
2001	119,099	4,500	62,012	123,420	7,818	33,620	30,469
2002	116,559	4,565	48,596	120,536	7,447	31,556	329,259
2003	115,636	4,691	51,526	120,992	7,278	29,684	329,807
2004	117,060	4,285	57,332	128,185	7,073	27,340	341,275
2005	121,535	4,283	66,691	145,725	6,945	27,341	372,520
2006	130,188	4,670	79,818	171,127	7,202	27,685	420,690
2007	141,239	4,842	84,525	197,100	7,975	27,431	463,112
2008	154,898	5,183	92,640	223,635	8,369	27,080	511,805
2009	155,150	5,538	67,756	193,589	8,753	26,753	457,539

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2011 , <http://www.bls.gov/cew/>

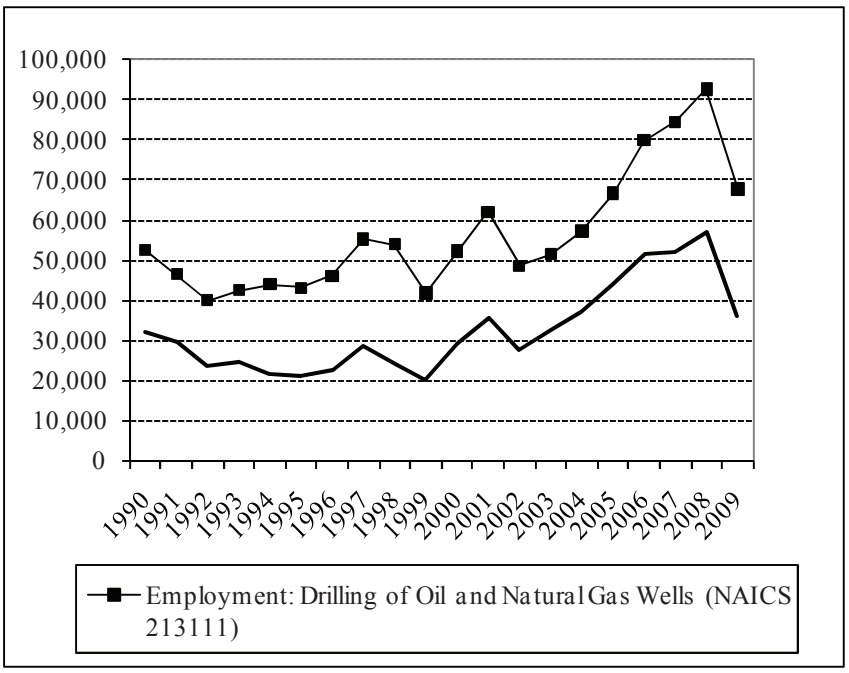


Figure 2-13 Employment in Drilling of Oil and Natural Gas Wells (NAICS 213111), and Total Oil and Natural Gas Wells Drilled, 1990-2009

Figure 2-13 compares employment in Drilling of Oil and Natural Gas Wells (NAICS 213111) with the total number of oil and natural gas wells drilled from 1990 to 2009. The figure depicts a strong positive correlation between employment in the sector with drilling activity. This correlation also holds throughout the period covered by the data.

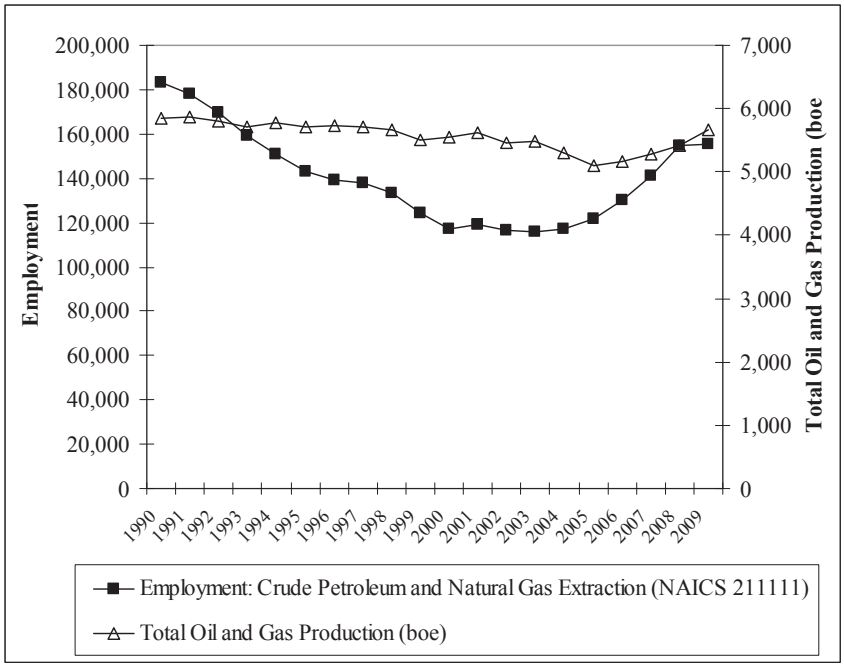


Figure 2-14 Employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Total Crude Oil and Natural Gas Production (boe), 1990-2009

Figure 2-14 compares employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) with total domestic oil and natural gas production from 1990 to 2009 in barrels of oil equivalent terms. While until 2003, employment in this sector and total production declined gradually, employment levels declined more rapidly. However, from 2004 to 2009 employment in Extraction recovered, rising to levels similar to the early 1990s.

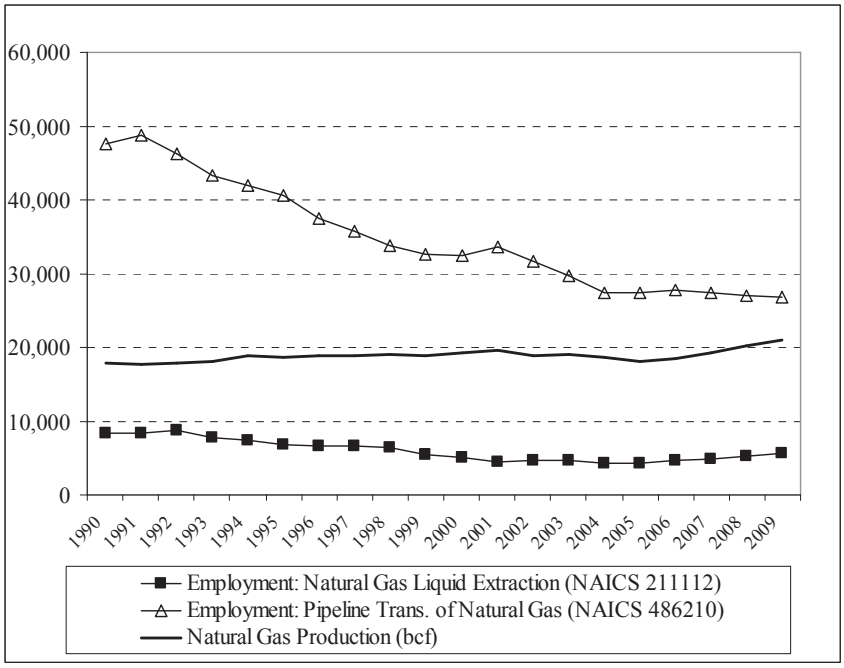


Figure 2-15 Employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009

Figure 2-15 depicts employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009. While total natural gas production has risen slightly over this time period, employment in natural gas pipeline transportation has steadily declined to almost half of its 1991 peak. Employment in natural gas liquid extraction declined from 1992 to a low in 2005, then rebounded slightly from 2006 to 2009. Overall, however, these trends depict these sectors becoming decreasingly labor intensive, unlike the trends depicted in Figure 2-13 and Figure 2-14.

From 1990 to 2009, average wages for the oil and natural gas industry have increased. Table 2-18 and Figure 2-16 show real wages (in 2008 dollars) from 1990 to 2009 for the NAICS codes associated with the oil and natural gas industry.

Table 2-18 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 (2008 dollars)

Year	Crude Petroleum and Natural Gas Extraction (211111)	Natural Gas Liquid Extraction (211112)	Drilling of Oil and Natural Gas Wells (213111)	Support Activities for Oil and Gas Operations (213112)	Pipeline Transportation of Crude Oil (486110)	Pipeline Transportation of Natural Gas (486210)	Total
1990	71,143	66,751	42,215	45,862	68,044	61,568	59,460
1991	72,430	66,722	43,462	47,261	68,900	65,040	60,901
1992	76,406	68,846	43,510	48,912	74,233	67,120	64,226
1993	77,479	68,915	45,302	50,228	72,929	67,522	64,618
1994	79,176	70,875	44,577	50,158	76,136	68,516	64,941
1995	81,433	67,628	46,243	50,854	78,930	71,965	66,446
1996	84,211	68,896	48,872	52,824	76,841	76,378	68,391
1997	89,876	79,450	52,180	55,600	78,435	82,775	71,813
1998	93,227	89,948	53,051	57,578	79,089	84,176	73,722
1999	98,395	89,451	54,533	59,814	82,564	94,471	79,078
2000	109,744	112,091	60,862	60,594	81,097	130,630	86,818
2001	111,101	111,192	61,833	61,362	83,374	122,386	85,333
2002	109,957	103,653	62,196	59,927	87,500	91,550	82,233
2003	110,593	112,650	61,022	61,282	87,388	91,502	82,557
2004	121,117	118,311	63,021	62,471	93,585	93,684	86,526
2005	127,243	127,716	70,772	67,225	92,074	90,279	90,292
2006	138,150	133,433	74,023	70,266	91,708	98,691	94,925
2007	135,510	132,731	82,010	71,979	96,020	105,441	96,216
2008	144,542	125,126	81,961	74,021	101,772	99,215	99,106
2009	133,575	123,922	80,902	70,277	100,063	100,449	96,298

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2011 , <http://www.bls.gov/cew/>

Employees in the NAICS 211 codes enjoy the highest average wages in the industry, while employees in the NAICS 213111 code have relatively lower wages. Average wages in natural gas pipeline transportation show the highest variation, with a rapid climb from 1990 to 2000, more than doubling in real terms. However, since 2000 wages have declined in the pipeline transportation sector, while wages have risen in the other NAICS.

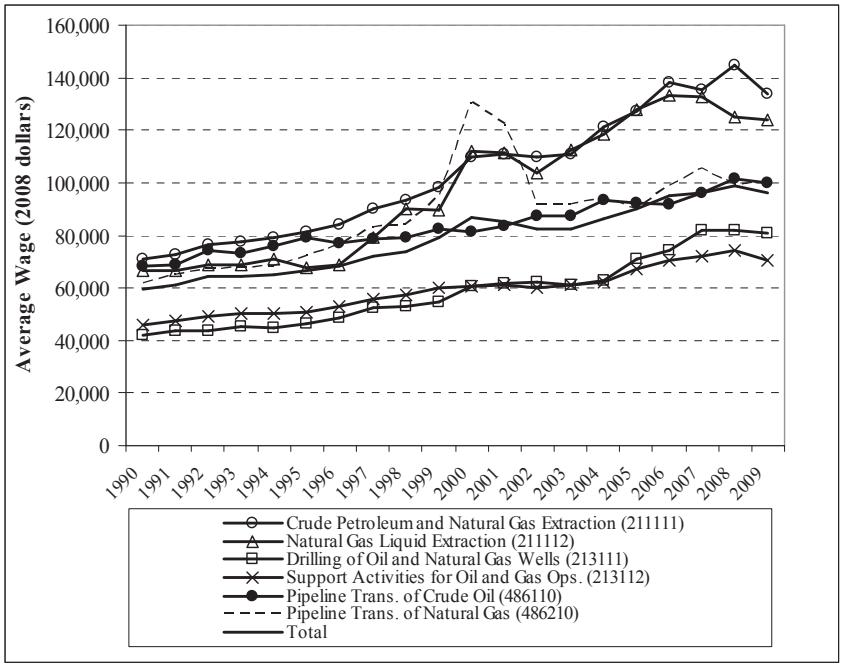


Figure 2-16 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 ($2008)

2.6.4 Horizontal and Vertical Integration

Because of the existence of major companies, the industry possesses a wide dispersion of vertical and horizontal integration. The vertical aspects of a firm's size reflect the extent to which goods and services that can be bought from outside are produced in house, while the horizontal aspect of a firm's size refers to the scale of production in a single-product firm or its scope in a multiproduct one. Vertical integration is a potentially important dimension in analyzing firm-level impacts because the regulation could affect a vertically integrated firm on more than one level. The regulation may affect companies for whom oil and natural gas production is only one of several processes in which the firm is involved. For example, a company that owns oil and natural gas production facilities may ultimately produce final petroleum products, such as motor gasoline, jet fuel, or kerosene. This firm would be considered vertically integrated because it is involved in more than one level of requiring crude oil and natural gas and finished petroleum products. A regulation that increases the cost of oil and natural gas production will ultimately affect the cost of producing final petroleum products.

Horizontal integration is also a potentially important dimension in firm-level analyses for any of the following reasons. A horizontally integrated firm may own many facilities of which

only some are directly affected by the regulation. Additionally, a horizontally integrated firm may own facilities in unaffected industries. This type of diversification would help mitigate the financial impacts of the regulation. A horizontally integrated firm could also be indirectly as well as directly affected by the regulation.

In addition to the vertical and horizontal integration that exists among the large firms in the industry, many major producers often diversify within the energy industry and produce a wide array of products unrelated to oil and gas production. As a result, some of the effects of regulation of oil and gas production can be mitigated if demand for other energy sources moves inversely compared to petroleum product demand.

In the natural gas sector of the industry, vertical integration is less predominant than in the oil sector. Transmission and local distribution of natural gas usually occur at individual firms, although processing is increasing performed by the integrated major companies. Several natural gas firms operate multiple facilities. However, natural gas wells are not exclusive to natural gas firms only. Typically wells produce both oil and gas and can be owned by a natural gas firm or an oil company.

Unlike the large integrated firms that have several profit centers such as refining, marketing, and transportation, most independents have to rely only on profits generated at the wellhead from the sale of oil and natural gas or the provision of oil and gas production-related engineering or financial services. Overall, independent producers typically sell their output to refineries or natural gas pipeline companies and are not vertically integrated. Independents may also own relatively few facilities, indicating limited horizontal integration.

2.6.5 Firm-level Information

The annual *Oil and Gas Journal* (OGJ) survey, the OGJ150, reports financial and operating results for top 150 public oil and natural gas companies with domestic reserves and headquarters in the U.S. In the past, the survey reported information on the top 300 companies, now the top 150. In 2010, only 137 companies are listed[3]. Table 2-19 lists selected statistics for

[3] Oil and Gas Journal. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010.

the top 20 companies in 2010. The results presented in the table reflect relatively lower production and financial figures as a result of the economic recession of this period.

Total earnings for the top 137 companies fell from 2008 to 2009 from $71 billion to $27 billion, reflecting the weak economy. Revenues for these companies also fell 35 percent during this period. 69 percent of the firms posted net losses in 2009, compared to 46 percent one year earlier (*Oil and Gas Journal*, September 6, 2010).

The total worldwide liquids production for the 137 firms declined 0.5 percent to 2.8 billion bbl, while total worldwide gas production increased about 3 percent to a total of 16.5 tcf (*Oil and Gas Journal*, September 6, 2010). Meanwhile, the 137 firms on the OGJ list increased both oil and natural gas production and reserves from 2008 to 2009. Domestic production of liquids increased about 7 percent to 1.1 billion bbl, and natural gas production increased to 10.1 tcf. For context, the OGJ150 domestic crude production represents about 57 percent of total domestic production (1.9 billion bbl, according to EIA). The OGJ150 natural gas production represents about 54 percent of total domestic production (18.8 tcf, according to EIA).

The OGJ also releases a period report entitled "Worldwide Gas Processing Survey", which provides a wide range of information on existing processing facilities. We used a recent list of U.S. gas processing facilities (*Oil and Gas Journal*, June 7, 2010) and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. As of 2009, there are 579 gas processing facilities in the U.S., with a processing capacity of 73,767 million cubic feet per day and throughout of 45,472 million cubic feet per day (Table 2-20). The overall trend in U.S. gas processing capacity is showing fewer, but larger facilities. For example, in 1995, there were 727 facilities with a capacity of 60,533 million cubic feet per day (U.S. DOE, 2006).

Trends in gas processing facility ownership are also showing a degree of concentration, as large firms own multiple facilities, which also tend to be relatively large facilities (Table 2-20). While we estimate 142 companies own the 579 facilities, the top 20 companies (in terms of total throughput) own 264 or 46 percent of the facilities. That larger companies tend to own larger facilities is indicated by these top 20 firms owning 86 percent of the total capacity and 88 percent of actual throughput.

Table 2-19 Top 20 Oil and Natural Gas Companies (Based on Total Assets), 2010

Rank by Total Assets	Company	Employees	Total Assets ($ millions)	Total Rev. ($ millions)	Net Inc. ($ millions)	Worldwide Production		U.S. Production		Net Wells Drilled
						Liquids (Million bbl)	Natural Gas (Bcf)	Liquids (Million bbl)	Natural Gas (Bcf)	
1	ExxonMobil Corp.	102,700	233,323	310,586	19,280	725	2,383	112	566	466
2	Chevron Corp.	64,000	164,621	171,636	10,563	674	1,821	177	511	594
3	ConocoPhillips	30,000	152,588	152,840	4,858	341	1,906	153	850	692
4	Anadarko Petroleum Corp.	4,300	50,123	9,000	-103	88	817	63	817	630
5	Marathon Oil Corp.	28,855	47,052	54,139	1,463	90	351	23	146	115
6	Occidental Petroleum Corp.	10,100	44,229	15,531	2,915	179	338	99	232	260
7	XTO Energy Inc.	3,129	36,255	9,064	2,019	32	855	32	855	1,059
8	Chesapeake Energy Corp.	8,200	29,914	7,702	-5,805	12	835	12	835	1,003
9	Devon Energy Corp.	5,400	29,686	8,015	-2,479	72	966	43	743	521
10	Hess Corp.	13,300	29,465	29,569	740	107	270	26	39	48
11	Apache Corp.	3,452	28,186	8,615	-284	106	642	35	243	124
12	El Paso Corp.	4,991	22,505	4,631	-539	6	219	6	215	134
13	EOG Resources Inc.	2,100	18,119	14,787	547	29	617	26	422	652
14	Murphy Oil Corp.	8,369	12,756	18,918	838	48	68	6	20	3
15	Noble Energy Inc.	1,630	11,807	2,313	-131	29	285	17	145	540
16	Williams Cos. Inc.	4,801	9,682	2,219	400	0	3,435	0	3,435	488
17	Questar Corp.	2,468	8,898	3,054	393	4	169	4	169	194
18	Pioneer Nat. Resources Co.	1,888	8,867	1,712	-52	19	157	17	148	67
19	Plains Expl. & Prod. Co.	808	7,735	1,187	136	18	78	18	78	53
20	Petrohawk Energy Corp.	469	6,662	41,084	-1,025	2	174	2	174	162

Source: *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010.
Notes: The source for employment figures is the American Business Directory.

Table 2-20 Top 20 Natural Gas Processing Firms (Based on Throughput), 2009

Rank	Company	Processing Plants (No.)	Natural Gas Capacity (MMcf/day)	Natural Gas Throughput (MMcf/day)
1	BP PLC	19	13,378	11,420
2	DCP Midstream Inc.	64	9,292	5,586
3	Enterprise Products Operating LP—	23	10,883	5,347
4	Targa Resources	16	4,501	2,565
5	Enbridge Energy Partners LP—	19	3,646	2,444
6	Williams Cos.	10	4,826	2,347
7	Martin Midstream Partners	16	3,384	2,092
8	Chevron Corp.	23	1,492	1,041
9	Devon Gas Services LP	6	1,038	846
10	ExxonMobil Corp.	6	1,238	766
11	Occidental Petroleum Corp	7	776	750
12	Kinder Morgan Energy Partners	9	1,318	743
13	Enogex Products Corp.	8	863	666
14	Hess Corp.	3	1,060	613
15	Norcen Explorer	1	600	500
16	Copano Energy	1	700	495
17	Anadarko	18	816	489
18	Oneok Field Services	10	1,751	472
19	Shell	4	801	446
20	DTE Energy	1	800	400
	TOTAL FOR TOP 20	264	63,163	40,028
	TOTAL FOR ALL COMPANIES	579	73,767	45,472

Source: *Oil and Gas Journal*. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010, with additional analysis to determine ultimate ownership of plants.

The OGJ also issues a periodic report on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies, which amounts to 136 companies in 2010 (*Oil and Gas Journal*, November 1, 2010). Table 2-21 presents the pipeline mileage, volumes of natural gas transported, operating revenue, and net income for the top 20 U.S. natural gas pipeline companies in 2009. Ownership of gas pipelines is mostly independent from ownership of oil and gas production companies, as is seen from the lack of overlap between the OGJ list of pipeline companies and the OGJ150. This observation shows that the pipeline industry is still largely based upon firms serving regional market.

The top 20 companies maintain about 63 percent of the total pipeline mileage and transport about 54 percent of the volume of the industry (Table 2-21). Operating revenues of the

top 20 companies equaled $11.5 billion, representing 60 percent of the total operating revenues for major and non-major companies. The top 20 companies also account for 64 percent of the net income of the industry.

Table 2-21 Performance of Top 20 Gas Pipeline Companies (Based on Net Income), 2009

Rank	Company	Transmission (miles)	Vol. trans for others (MMcf)	Op. Rev. (thousand $)	Net Income
1	Natural Gas Pipeline Co of America	9,312	1,966,774	1,131,548	348,177
2	Dominion Transmission Inc.	3,452	609,193	831,773	212,365
3	Columbia Gas Transmission LLC	9,794	1,249,188	796,437	200,447
4	Panhandle Eastern Pipe Line Co. LP	5,894	675,616	377,563	196,825
5	Transcontinental Gas Pipe Line Co. LLC	9,362	2,453,295	1,158,665	192,830
6	Texas Eastern Transmission LP	9,314	1,667,593	870,812	179,781
7	Northern Natural Gas Co.	15,028	922,745	690,863	171,427
8	Florida Gas Transmission Co. LLC	4,852	821,297	520,641	164,792
9	Tennessee Gas Pipeline Co.	14,113	1,704,976	820,273	147,378
10	Southern Natural Gas Co.	7,563	867,901	510,500	137,460
11	El Paso Natural Gas Co.	10,235	1,493,213	592,503	126,000
12	Gas Transmission Northwest Corp.	1,356	809,206	216,526	122,850
13	Rockies Express Pipeline LLC	1,682	721,840	555,288	117,243
14	CenterPoint Energy Gas Transmission Co.	6,162	1,292,931	513,315	116,979
15	Colorado Interstate Gas Co.	4,200	839,184	384,517	108,483
16	Kern River Gas Transmission Co.	1,680	789,858	371,951	103,430
17	Trunkline LNG Co. LLC	—	—	134,150	101,920
18	Northwest Pipeline GP	3,895	817,832	434,379	99,340
19	Texas Gas Transmission LLC	5,881	1,006,906	361,406	91,575
20	Algonquin Gas Transmission LLC	1,128	388,366	237,291	82,472
	TOTAL FOR TOP 20	124,903	21,097,914	11,510,401	3,021,774
	TOTAL FOR ALL COMPANIES	198,381	38,793,532	18,934,674	4,724,456

Source: *Oil and Gas Journal*. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

2.6.6 Financial Performance and Condition

From a broad industry perspective, the EIA Financial Reporting System (FRS) collects financial and operating information from a subset of the U.S. major energy producing companies. This information is used in annual report to Congress, as well as is released to the public in aggregate form. While the companies that report information to FRS each year changes, EIA makes an effort to retain sufficient consistency such that trends can be evaluated.

For 2008, there are 27 companies in the FRS[4] that accounted for 41 percent of total U.S. crude oil and NGL production, 43 percent of natural gas production, 77 percent of U.S. refining capacity, and 0.2 percent of U.S. electricity net generation (U.S. EIA, 2010). Table 2-22 shows a series of financial trends in 2008 dollars selected and aggregated from FRS firms' financial statements. The table shows operating revenues and expenses rising significantly from 1990 to 2008, with operating income (the difference between operating revenues and expenses) rising as well. Interest expenses remained relatively flat during this period. Meanwhile, recent years have shown that other income and income taxes have played a more significant role for the industry. Net income has risen as well, although 2008 saw a decline from previous periods, as oil and natural gas prices declined significantly during the latter half of 2008.

Table 2-22 Selected Financial Items from Income Statements (Billion 2008 Dollars)

Year	Operating Revenues	Operating Expenses	Operating Income	Interest Expense	Other Income*	Income Taxes	Net Income
1990	766.9	706.4	60.5	16.8	13.6	24.8	32.5
1991	673.4	635.7	37.7	14.4	13.4	15.4	21.3
1992	670.2	637.2	33.0	12.7	-5.6	12.2	2.5
1993	621.4	586.6	34.8	11.0	10.3	12.7	21.5
1994	606.5	565.6	40.9	10.8	6.8	14.4	22.5
1995	640.8	597.5	43.3	11.1	12.9	17.0	28.1
1996	706.8	643.3	63.6	9.1	13.4	26.1	41.8
1997	673.6	613.8	59.9	8.2	13.4	23.9	41.2
1998	614.2	594.1	20.1	9.2	11.0	6.0	15.9
1999	722.9	682.6	40.3	10.9	12.7	13.6	28.6
2000	1,114.3	1,011.8	102.5	12.9	18.4	42.9	65.1
2001	961.8	880.3	81.5	10.8	7.6	33.1	45.2
2002	823.0	776.9	46.2	12.7	7.9	17.2	24.3
2003	966.9	872.9	94.0	10.1	19.5	37.2	66.2
2004	1,188.5	1,051.1	137.4	12.4	20.1	54.2	90.9
2005	1,447.3	1,263.8	183.5	11.6	34.6	77.1	129.3
2006	1,459.0	1,255.0	204.0	12.4	41.2	94.8	138.0
2007	1,475.0	1,297.7	177.3	11.1	47.5	86.3	127.4
2008	1,818.1	1,654.0	164.1	11.4	32.6	98.5	86.9

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). * Other Income includes other revenue and expense (excluding interest expense), discontinued operations, extraordinary items, and accounting changes. Totals may not sum due to independent rounding.

[4] Alenco, Anadarko Petroleum Corporation, Apache Corporation, BP America, Inc., Chesapeake Energy Corporation, Chevron Corporation, CITGO Petroleum Corporation, ConocoPhillips, Devon Energy Corporation, El Paso Corporation, EOG Resources, Inc., Equitable Resources, Inc., Exxon Mobil Corporation, Hess Corporation, Hovensa, Lyondell Chemical Corporation, Marathon Oil Corporation, Motiva Enterprises, L.L.C., Occidental Petroleum Corporation, Shell Oil Company, Sunoco, Inc., Tesoro Petroleum Corporation, The Williams Companies, Inc., Total Holdings USA, Inc., Valero Energy Corp., WRB Refining LLC, and XTO Energy, Inc.

Table 2-23 shows in percentage terms the estimated return on investments for a variety of business lines, in 1998, 2003, and 2008, for FRS companies. For U.S. petroleum-related business activities, oil and natural gas production has remained the most profitable line of business relative to refining/marketing and pipelines, sustaining a return on investment greater than 10 percent for the three years evaluated. Returns to foreign oil and natural gas production rose above domestic production in 2008. Electric power generation and sales emerged in 2008 as a highly profitable line of business for the FRS companies.

Table 2-23 Return on Investment for Lines of Business (all FRS), for 1998, 2003, and 2008 (percent)

Line of Business	1998	2003	2008
Petroleum	10.8	13.4	12.0
U.S. Petroleum	10	13.7	8.2
Oil and Natural Gas Production	12.5	16.5	10.7
Refining/Marketing	6.6	9.3	2.6
Pipelines	6.7	11.5	2.4
Foreign Petroleum	11.9	13.0	17.8
Oil and Natural Gas Production	12.5	14.2	16.3
Refining/Marketing	10.6	8.0	26.3
Downstream Natural Gas*	-	8.8	5.1
Electric Power*	-	5.2	181.4
Other Energy	7.1	2.8	-2.1
Non-energy	10.9	2.4	-5.3

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). Note: Return on investment measured as contribution to net income/net investment in place. * The downstream natural gas and electric power lines of business were added to the EIA-28 survey form beginning with the 2003 reporting year.

The oil and natural gas industry also produces significant tax revenues for local, state, and federal authorities. Table 2-24 shows income and production tax trends from 1990 to 2008 for FRS companies. The column with U.S. federal, state, and local taxes paid or accrued includes deductions for the U.S. Federal Investment Tax Credit ($198 million in 2008) and the effect of the Alternative Minimum Tax ($34 million in 2008). Income taxes paid to state and local authorizes were $3,060 million in 2008, about 13 percent of the total paid to U.S. authorities.

Table 2-24 Income and Production Taxes, 1990-2008 (Million 2008 Dollars)

Year	U.S. Federal, State, and Local Taxes Paid or Accrued	Total Current	Total Deferred	Total Income Tax Expense	Other Non-Income Production Taxes Paid
1990	9,568	25,056	-230	24,826	4,341
1991	6,672	18,437	-3,027	15,410	3,467
1992	4,994	16,345	-4,116	12,229	3,097
1993	3,901	13,983	-1,302	12,681	2,910
1994	3,348	13,556	887	14,443	2,513
1995	6,817	17,474	-510	16,965	2,476
1996	8,376	22,493	3,626	26,119	2,922
1997	7,643	20,764	3,141	23,904	2,743
1998	1,199	7,375	-1,401	5,974	1,552
1999	2,626	13,410	140	13,550	2,147
2000	14,308	36,187	6,674	42,861	3,254
2001	10,773	28,745	4,351	33,097	3,042
2002	814	17,108	46	17,154	2,617
2003	9,274	30,349	6,879	37,228	3,636
2004	19,661	50,185	4,024	54,209	3,990
2005	29,993	72,595	4,529	77,125	5,331
2006	29,469	85,607	9,226	94,834	5,932
2007	28,332	84,119	2,188	86,306	7,501
2008	23,199	95,590	2,866	98,456	12,507

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The difference between total current taxes and U.S. federal, state, and local taxes in includes taxes and royalties paid to foreign countries. As can be seen in Table 2-24, foreign taxes paid far exceeds domestic taxes paid. Other non-income production taxes paid, which have risen almost three-fold between 1990 and 2008, include windfall profit and severance taxes, as well as other production-related taxes.

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3 EMISSIONS AND ENGINEERING COSTS

3.1 Introduction

This section includes three sets of discussions for both the proposed NSPS and NESHAP amendments:

- Emission Sources and Points
- Emissions Control Options
- Engineering Cost Analysis

3.2 Emissions Points, Controls, and Engineering Costs Analysis

This section discusses the emissions points and pollution control options for the proposed NSPS and NESHAP amendments. This discussion of emissions points and control options is meant to assist the reader of the RIA in better understanding the economic impact analysis. However, we provide reference to the detailed technical memoranda prepared by the Office of Air Quality Planning and Standards (OAQPS) for the reader interested in a greater level of detail. This section also presents the engineering cost analysis, which provides a cost basis for the energy system, welfare, employment, and small business analyses.

Before going into detail on emissions points and pollution controls, it is useful to provide estimates of overall emissions from the crude oil and natural industry to provide context for estimated reductions as a result of the regulatory options evaluated. To estimate VOC emissions from the oil and gas sector, we modified the emissions estimate for the crude oil and natural gas sector in the 2008 National Emissions Inventory (NEI). During this review, EPA identified VOC emissions from natural gas sources which are likely relatively under-represented in the NEI, natural gas well completions primarily. Crude oil and natural gas sector VOC emissions estimated in the 2008 NEI total approximately 1.76 million tons. Of these emissions, the NEI identifies about 21 thousand tons emitted from natural gas well completion processes. We substituted the estimates of VOC emissions from natural gas well completions estimated as part of the engineering analysis (510,000 tons, which is discussed in more detail in the next section), bringing the total estimated VOC emissions from the crude oil and natural gas sector to about 2.24 million tons VOC.

The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009 (published April 2011) estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 251.55 ($MMtCO_2$-e). It is important to note that the 2009 emissions estimates from well completions and recompletions exclude a significant number of wells completed in tight sand plays and the Marcellus Shale, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays and the Marcellus Shale, and such an adjustment is also being considered as a planned improvement in next year's Inventory. This adjustment would increase the 2009 Inventory estimate by about 80 $MMtCO_2$-e to approximately 330 $MMtCO_2$-e.

3.2.1 Emission Points and Pollution Controls assessed in the RIA

3.2.1.1 NSPS Emission Points and Pollution Controls

A series of emissions controls were evaluated as part of the NSPS review. This section provides a basic description of possible emissions sources and the controls evaluated for each source to facilitate the reader's understanding of the economic impact and benefit analyses. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant chapters within the Technical Support Document (TSD) which is published in the Docket. The chapters are also referenced below. EPA is soliciting public comment and data relevant to several emissions-related issues related to the proposed NSPS. The comments we receive during the public comment period will help inform the rule development process as we work toward promulgating a final action.

Centrifugal and reciprocating compressors (TSD Chapter 6)**:** There are many locations throughout the oil and gas sector where compression of natural gas is required to move the gas along the pipeline. This is accomplished by compressors powered by combustion turbines, reciprocating internal combustion engines, or electric motors. Turbine-powered compressors use a small portion of the natural gas that they compress to fuel the turbine. The turbine operates a centrifugal compressor, which compresses and pumps the natural gas through the pipeline. Sometimes an electric motor is used to turn a centrifugal compressor. This type of compression does not require the use of any of the natural gas from the pipeline, but it does require a source of electricity. Reciprocating spark ignition engines are also used to power many compressors,

referred to as reciprocating compressors, since they compress gas using pistons that are driven by the engine. Like combustion turbines, these engines are fueled by natural gas from the pipeline.

Both centrifugal and reciprocating compressors are sources of VOC emissions, and EPA evaluated compressors for coverage under the NSPS. Centrifugal compressors require seals around the rotating shaft to prevent gases from escaping where the shaft exits the compressor casing. The seals in some compressors use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. Very little gas escapes through the oil barrier, but considerable gas is absorbed by the oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated, and the gas is commonly vented to the atmosphere. These are commonly called "wet" seals. An alternative to a wet seal system is the mechanical dry seal system. This seal system does not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and static pressure. Fugitive VOC is emitted from dry seals around the compressor shaft. The use of dry gas seals substantially reduces emissions. In addition, they significantly reduce operating costs and enhance compressor efficiency.

Reciprocating compressors in the natural gas industry leak natural gas during normal operation. The highest volume of gas loss is associated with piston rod packing systems. Packing systems are used to maintain a tight seal around the piston rod, preventing the gas compressed to high pressure in the compressor cylinder from leaking, while allowing the rod to move freely. Monitoring and replacing compressor rod packing systems on a regular basis can greatly reduce VOC emissions.

Equipment leaks (TSD Chapter 8)**:** Equipment leaks are fugitive emissions emanating from valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines, and other process and operation components. There are several potential reasons for equipment leak emissions. Components such as pumps, valves, pressure relief valves, flanges, agitators, and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines, and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. Because of the large number of valves, pumps, and other components within an oil

and gas production, processing, and transmission facility, equipment leaks of volatile emissions from these components can be significant. Natural gas processing plants, especially those using refrigerated absorption, and transmission stations tend to have a large number of components. These types of equipment also exist at production sites and gas transmission/compressor stations. While the number of components at individual transmission/compressor stations is relatively smaller than at processing plants, collectively there are many components that can result in significant emissions. Therefore, EPA evaluated NSPS for equipment leaks for facilities in the production segment of the industry, which includes everything from the wellhead to the point that the gas enters the processing plant or refinery.

Pneumatic controllers (TSD Chapter 5): Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, delta-pressure, and temperature. Pneumatic controllers are widely used in the oil and natural gas sector. In many situations, the pneumatic controllers used in the oil and gas sector make use of the available high-pressure natural gas to regulate temperature, pressure, liquid level, and flow rate across all areas of the industry. In these "gas-driven" pneumatic controllers, natural gas may be released with every valve movement or continuously from the valve control pilot. Not all pneumatic controllers are gas driven. These "non-gas driven" pneumatic controllers use sources of power other than pressurized natural gas. Examples include solar, electric, and instrument air. At oil and gas locations with electrical service, non gas-driven controllers are typically used. Gas-driven pneumatic controllers are typically characterized as "high-bleed" or "low-bleed", where a high-bleed device releases at least 6 cubic feet of gas per hour. EPA evaluated the impact of requiring low-bleed controllers.

Storage vessels (TSD Chapter 7): Crude oil, condensate, and produced water are typically stored in fixed-roof storage vessels. Some vessels used for storing produced water may be open-top tanks. These vessels, which are operated at or near atmospheric pressure conditions, are typically located at tank batteries. A tank battery refers to the collection of process equipment used to separate, treat, and store crude oil, condensate, natural gas, and produced water. The extracted products from productions wells enter the tank battery through the production header, which may collect product from many wells. Emissions from storage vessels are a result of

working, breathing, and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flashing emission will occur in the storage stage. The two ways of controlling tanks with significant emissions would be to install a vapor recovery unit (VRU) and recover all the vapors from the tanks or to route the emissions from the tanks to a control device.

Well completions (TSD Chapter 4): In the oil and natural gas sector, well completions contain multi-phase processes with various sources of emissions. One specific emission source during completion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during activities that involve re-drilling or re-fracturing an existing well. Well completions include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production.

Hydraulic fracturing is one completion step for improving gas production where the reservoir rock is fractured with very high pressure fluid, typically water emulsion with proppant (generally sand) that "props open" the fractures after fluid pressure is reduced. Emissions are a result of the backflow of the fracture fluids and reservoir gas at high velocity necessary to lift excess proppant to the surface. This multi-phase mixture is often directed to a surface impoundment where natural gas and VOC vapors escape to the atmosphere during the collection of water, sand, and hydrocarbon liquids. As the fracture fluids are depleted, the backflow eventually contains more volume of natural gas from the formation. Thus, we estimate completions involving hydraulic fracturing vent substantially more natural gas, approximately 230 times more, than completions not involving hydraulic fracturing. Specifically, we estimate

that uncontrolled well completion emissions for a hydraulically fractured well are about 23 tons of VOC, where emissions for a conventional gas well completion are around 0.1 ton VOC. Our data indicate that hydraulically fractured wells have higher emissions but we believe some wells that are not hydraulically fractured may have higher emissions than our data show, or in some cases, hydraulically fractured wells could have lower emissions that our data show.

Reduced emission completions, which are sometimes referred to as "green completions" or "flareless completions," use equipment at the well site to capture and treat gas so it can be directed into the sales line and avoid emissions from venting. Equipment required to conduct a reduced emissions completion may include tankage, special gas-liquid-sand separator traps, and gas dehydration. Equipment costs associated with reduced emission completions will vary from well to well. Based on information provided to the EPA Natural Gas STAR program, 90 percent of gas potentially vented during a completion can be recovered during a reduced emission completion.

3.2.1.2 NESHAP Emission Points and Pollution Controls

A series of emissions controls will be required under the proposed NESHAP Amendments. This section provides a basic description of potential sources of emissions and the controls intended for each to facilitate the reader's understanding of the economic impacts and subsequent benefits analysis section. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant technical memos which are published in the Docket. The memos are also referenced below.

Glycol dehydrators[5]: Once natural gas has been separated from any liquid materials or products (e.g., crude oil, condensate, or produced water), residual entrained water is removed from the natural gas by dehydration. Dehydration is necessary because water vapor may form hydrates, which are ice-like structures, and can cause corrosion in or plug equipment lines. The most widely used natural gas dehydration processes are glycol dehydration and solid desiccant

[5] Memorandum. Brown, Heather, EC/R Incorporated, to Bruce Moore and Greg Nizich, EPA/OAQPS/SPPD/FIG. Oil and Natural Gas Production MACT and Natural Gas Transmission and Storage MACT - Glycol Dehydrators: Impacts of MACT Review Options. July 17,2011.

dehydration. Solid desiccant dehydration, which is typically only used for lower throughputs, uses adsorption to remove water and is not a source of HAP emissions. Glycol dehydration is an absorption process in which a liquid absorbent, glycol, directly contacts the natural gas stream and absorbs any entrained water vapor in a contact tower or absorption column. The rich glycol, which has absorbed water vapor from the natural gas stream, leaves the bottom of the absorption column and is directed either to (1) a gas condensate glycol separator (GCG separator or flash tank) and then a reboiler or (2) directly to a reboiler where the water is boiled off of the rich glycol. The regenerated glycol (lean glycol) is circulated, by pump, into the absorption tower. The vapor generated in the reboiler is directed to the reboiler vent. The reboiler vent is a source of HAP emissions. In the glycol contact tower, glycol not only absorbs water but also absorbs selected hydrocarbons, including BTEX and n-hexane. The hydrocarbons are boiled off along with the water in the reboiler and vented to the atmosphere or to a control device.

The most commonly used control device is a condenser. Condensers not only reduce emissions, but also recover condensable hydrocarbon vapors that can be recovered and sold. In addition, the dry non-condensable off-gas from the condenser may be used as fuel or recycled into the production process or directed to a flare, incinerator, or other combustion device.

If present, the GCG separator (flash tank) is also a potential source of HAP emissions. Some glycol dehydration units use flash tanks prior to the reboiler to separate entrained gases, primarily methane and ethane from the glycol. The flash tank off-gases are typically recovered as fuel or recycled to the natural gas production header. However, the flash tank may also be vented directly to the atmosphere. Flash tanks typically enhance the reboiler condenser's emission reduction efficiency by reducing the concentration of non-condensable gases present in the stream prior to being introduced into the condenser.

Storage vessels: Please see the discussion of storage vessels in the NSPS section above.

3.2.2 Engineering Cost Analysis

In this section, we provide an overview of the engineering cost analysis used to estimate the additional private expenditures industry may make in order to comply with the proposed

NSPS and NESHAP amendments. A detailed discussion of the methodology used to estimate cost impacts is presented in series of memos published in the Docket as part of the TSD.

3.2.2.1 NSPS Sources

Table 3-1 shows the emissions sources, points, and controls analyzed in three NSPS regulatory options, which we term Option 1, Option 2, and Option 3. Option 2 was selected for proposal. The proposed Option 2 contains reduced emission completion (REC) and completion combustion requirements for a subset of newly drilled natural gas wells that are hydraulically fractured. Option 2 also requires a subset of wells that are worked over, or recompleted, using hydraulic fracturing to implement RECs. The proposed Option 2 requires emissions reductions from reciprocating compressors at gathering and boosting stations, processing plants, transmission compressor stations, and underground storage facilities. The proposed Option 2 also requires emissions reductions from centrifugal compressors, processing plants, and transmission compressor stations. Finally, the proposed Option 2 requires emissions reductions from pneumatic controllers at oil and gas production facilities and natural gas transmission and storage and reductions from high throughput storage vessels.

Table 3-1 Emissions Sources, Points, and Controls Included in NSPS Options

Emissions Sources and Points	Emissions Control	Option 1	Option 2 (proposed)	Option 3
Well Completions of Post-NSPS Wells				
Hydraulically Fractured Gas Wells that Meet Criteria for Reduced Emissions Completion (REC)	REC	**X**	**X**	**X**
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC	Combustion	**X**	**X**	**X**
Conventional Gas Wells	Combustion			
Oil Wells	Combustion			
Well Recompletions				
Hydraulically Fractured Gas Wells (post-NSPS wells)	REC	**X**	**X**	**X**
Hydraulically Fractured Gas Wells (pre-NSPS wells)	REC		**X**	**X**
Conventional Gas Wells	Combustion			
Oil Wells	Combustion			
Equipment Leaks				
Well Pads	NSPS Subpart VV			**X**
Gathering and Boosting Stations	NSPS Subpart VV			**X**
Processing Plants	NSPS Subpart VVa		**X**	**X**
Transmission Compressor Stations	NSPS Subpart VV			**X**
Reciprocating Compressors				
Well Pads	Annual Monitoring/ Maintenance (AMM)			
Gathering/Boosting Stations	AMM	**X**	**X**	**X**
Processing Plants	AMM	**X**	**X**	**X**
Transmission Compressor Stations	AMM	**X**	**X**	**X**
Underground Storage Facilities	AMM	**X**	**X**	**X**
Centrifugal Compressors				
Processing Plants	Dry Seals/Route to Process or Control	**X**	**X**	**X**
Transmission Compressor Stations	Dry Seals/Route to Process or Control	**X**	**X**	**X**
Pneumatic Controllers -				
Oil and Gas Production	Low Bleed/Route to Process	**X**	**X**	**X**
Natural Gas Transmission and Storage	Low Bleed/Route to Process	**X**	**X**	**X**
Storage Vessels				
High Throughput	95% control	**X**	**X**	**X**
Low Throughput	95% control			

The distinction between Option 1 and the proposed Option 2 is the inclusion of completion combustion and REC requirements for recompletions at existing wells and an equipment leak standard for natural gas processing plants in Option 2. Option 2 requires the implementation of completion combustion and REC for existing wells as well as wells completed after the implementation date of the proposed NSPS. Option 1 applies the requirement only to new wells, not existing wells. The main distinction between proposed Option 2 and Option 3 is the inclusion of a suite of equipment leak standards. These equipment leak standards would apply at well pads, gathering and boosting stations, and transmission compressor stations. Option 1 differs from Option 3 in that it does not include the combustion and REC requirements at existing wells or the full suite of equipment leak standards.

Table 3-2 summarizes the unit level capital and annualized costs for the evaluated NSPS emissions sources and points. The detailed description of costs estimates is provided in the series of technical memos included in the TSD in the document, as referenced in Section 3.2.1 of this RIA. The table also includes the projected number of affected units. Four issues are important to note on Table 3-2: the approach to annualizing costs, the projection of affected units in the baseline; that capital and annualized costs are equated for RECs; and additional natural gas and hydrocarbon condensates that would otherwise be emitted to the environment are recovered from several control options evaluated in the NSPS review.

First, engineering capital costs were annualized using a 7 percent interest rate. However, different emissions control options were annualized using expected lifetimes that were determined to be most appropriate for individual options. For control options evaluated for the NSPS, the following lifetimes were used:

- Reduced emissions completions and combustion devices: 1 year (more discussion of the selection of a one-year lifetime follows in this section momentarily)
- Reciprocating compressors: 3 years
- Centrifugal compressors and pneumatic controllers: 10 years
- Storage vessels: 15 years
- Equipment leaks: 5 to 10 years, depending on specific control

To estimate total annualized engineering compliance costs, we added the annualized costs of each item without accounting for different expected lifetimes. An alternative approach would be to establish an overall, representative project time horizon and annualize costs after consideration of control options that would need to be replaced periodically within the given time horizon. For example, a 15 year project would require replacing reciprocating compressor-related controls five times, but only require a single installation of controls on storage vessels. This approach, however, is equivalent to the approach selected; that is to sum the annualized costs across options, without establishing a representative project time horizon.

Second, the projected number of affected units is the number of units that our analysis shows would be affected in 2015, the analysis year. The projected number of affected units accounts for estimates of the adoption of controls in absence of Federal regulation. While the procedures used to estimate adoption in absence of Federal regulation are presented in detail within the TSD, because REC requirements provide a significant component of the estimated emissions reductions and engineering compliance costs, it is worthwhile to go into some detail on the projected number of RECs within the RIA. We use EIA projections consistent with the Annual Energy Outlook 2011 to estimate the number of natural gas well completions with hydraulic fracturing in 2015, assuming that successful wells drilled in coal bed methane, shale, and tight sands used hydraulic fracturing. Based on this assumption, we estimate that 11,403 wells were successfully completed and used hydraulic fracturing. To approximate the number of wells that would not be required to perform RECs because of the absence of sufficient infrastructure, we draw upon the distinction in EIA analysis between exploratory and developmental wells. We assume exploratory wells do not have sufficient access to infrastructure to perform a REC and are exempt from the REC requirement. These 446 wells are removed from the REC estimate and are assumed to combust emissions using pit flares.

The number of hydraulically fractured recompletions of existing wells was approximated using assumptions found in Subpart W's TSD[6] and applied to well count data found in the proprietary HPDI® database. The underlying assumption is that wells found in coal bed

[6] U.S. Environmental Protection Agency (U.S. EPA). 2010. Greenhouse Gas Emissions Reporting From the Petroleum and Natural Gas Industry: Background Technical Support Document. Climate Change Division. Washington, DC.

methane, shale, and tight sand formations require re-fracture, on average, every 10 years. In other words, 10 percent of the total wells classified as being performed with hydraulic fracturing would perform a recompletion in any given year. Natural gas well recompletions performed without hydraulic fracturing were based only on 2008 well data from HPDI®.

The number of completions and recompletions already controlling emissions in absence of a Federal regulation was estimated based on existing State regulations that require applicable control measures for completions and workovers in specific geographic locations. Based on this criterion, 15 percent of natural gas completions with hydraulic fracturing and 15 percent of existing natural gas workovers with hydraulic fracturing are estimated to be controlled by either flare or REC in absence of Federal regulations. Completions and recompletions without hydraulic fracturing were assumed as having no controls in absence of a Federal regulation. Following these procedures leads to an estimate of 9,313 completions of new wells and 12,050 recompletions of existing wells that will require either a REC under the proposed NSPS in 2015.

It should be noted that natural gas prices are stochastic and, historically, there have been periods where prices have increased or decreased rapidly. These price changes would be expected to affect adoption of emission reduction technologies in absence of regulation, particularly control measures such as RECs that capture emission significantly over short periods of time.

Third, for well completion requirements, annualized costs are set equal to capital costs. We chose to equate the capital and annualized cost because the completion requirements (combustion and RECs) are essentially one-shot events; the emissions controls are applied over the course of a well completion, which will typically range over a few days to a couple of weeks. After this relatively short period of time, there is no continuing control requirement, unless the well is again completed at a later date, sometimes years later. We reasoned that the absence of a continuing requirement makes it appropriate to equate capital and annualized costs.

Fourth, for annualized cost, we present two figures, the annualized costs with revenues from additional natural gas and condensate recovery and annualized costs without additional revenues this product recovery. Several emission controls for the NSPS capture VOC emissions

that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOCs, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. When including the additional natural gas recovery in the cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. RECs also capture saleable condensates that would otherwise be lost to the environment. The engineering analysis assumes a REC will capture 34 barrels of condensate per REC and that the value of this condensate is $70/barrel.

The assumed price for natural gas is within the range of variation of wellhead prices for the 2010-11 period. The $4/Mcf is below the 2015 EIA-forecasted wellhead price, $4.22/Mcf in 2008 dollars. The $4/Mcf payment rate does not reflect any taxes or tax credits that might apply to producers implementing the control technologies. As natural gas prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional natural gas recovery is included. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. A $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million in 2008 dollars.

As will be seen in subsequent analysis, the estimate of revenues from additional product recovery is critical to the economic impact analysis. However, before discussing this assumption in more depth, it is important to further develop the engineering estimates to contextualize the discussion and to provide insight into why, if it is profitable to capture natural gas emissions that are otherwise vented, producers may not already be doing so.

Table 3-3 presents the estimated nationwide compliance costs, emissions reductions, and VOC reduction cost-effectiveness broken down by emissions sources and points for those sources and points evaluated in the NSPS analysis. The reporting and recordkeeping costs for the proposed NSPS Option 2 are estimated at $18,805,398 and are included in Table 3-3. Because of time constraints, we were unable to estimate reporting and recordkeeping costs customized for Options 1 and 3; for these options, we use the same $18,805,398 for reporting and recordkeeping costs for these options.

As can be seen from Table 3-3 controls associated with well completions and recompletions of hydraulically fractured wells provide the largest potential for emissions

reductions from evaluated emissions sources and points, as well as present the most significant compliance costs if revenue from additional natural gas recovery is not included. Emissions reductions from conventional natural gas wells and crude oil wells are clearly not as significant as the potential from hydraulically fractured wells, as was discussed in Section 3.2.1.1.

Several evaluated emissions sources and points are estimated to have net financial savings when including the revenue from additional natural gas recovery. These sources form the core of the three NSPS options evaluated in this RIA. Table 3-4 presents the estimated engineering costs, emissions reductions, and VOC reduction cost-effectiveness for the three NSPS options evaluated in the RIA. The resulting total national annualized cost impact of the proposed NSPS rule (Option 2) is estimated at $740 million per year without considering revenues from additional natural gas recovery. Annual costs for the proposed NSPS are estimated at -$45 million when revenue from additional natural gas recovery is included. All figures are in 2008 dollars.

Table 3-2 Summary of Capital and Annualized Costs per Unit for NSPS Emissions Points

Sources/Emissions Point	Projected No. of Affected Units	Capital Costs (2008$)	Per Unit Annualized Cost (2008$)	
			Without Revenues from Additional Product Recovery	With Revenues from Additional Product Recovery
Well Completions				
Hydraulically Fractured Gas Wells that Meet Criteria for REC	9,313	$33,237	$33,237	-$2,173
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	446	$3,523	$3,523	$3,523
Conventional Gas Wells	7,694	$3,523	$3,523	$3,523
Oil Wells	12,193	$3,523	$3,523	$3,523
Well Recompletions				
Hydraulically Fractured Gas Wells (existing wells)	12,050	$33,237	$33,237	-$2,173
Conventional Gas Wells	42,342	$3,523	$3,523	$3,523
Oil Wells	39,375	$3,523	$3,523	$3,523
Equipment Leaks				
Well Pads	4,774	$68,970	$23,413	$21,871
Gathering and Boosting Stations	275	$239,494	$57,063	$51,174
Processing Plants	29	$7,522	$45,160	$33,884
Transmission Compressor Stations	107	$96,542	$25,350	$25,350
Reciprocating Compressors				
Well Pads	6,000	$6,480	$3,701	$3,664
Gathering/Boosting Stations	210	$5,346	$2,456	$870
Processing Plants	209	$4,050	$2,090	-$2,227
Transmission Compressor Stations	20	$5,346	$2,456	$2,456
Underground Storage Facilities	4	$7,290	$3,349	$3,349
Centrifugal Compressors				
Processing Plants	16	$75,000	$10,678	-$123,730
Transmission Compressor Stations	14	$75,000	$10,678	-$77,622
Pneumatic Controllers -				
Oil and Gas Production	13,632	$165	$23	-$1,519
Natural Gas Trans. and Storage	67	$165	$23	$23
Storage Vessels				
High Throughput	304	$65,243	$14,528	$13,946
Low Throughput	17,086	$65,243	$14,528	$13,946

Table 3-3 Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by Emissions Sources and Points, NSPS, 2015

Source/Emissions Point	Emissions Control	Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
		Without Addl. Revenues	With Addl. Revenues	VOC	Methane	HAP	Without Addl. Revenues	With Addl. Revenues
Well Completions (New Wells)								
Hydraulically Fractured Gas Wells	REC	$309,553,517	-$20,235,748	204,134	1,399,139	14,831	$1,516	-$99
Hydraulically Fractured Gas Wells	Combustion	$1,571,188	$1,571,188	9,801	67,178	712	$160	$160
Conventional Gas Wells	Combustion	$27,104,761	$27,104,761	857	5,875	62	$31,619	$31,619
Oil Wells	Combustion	$42,954,036	$42,954,036	83	88	0	$520,580	$520,580
Well Recompletions (Existing Wells)								
Hydraulically Fractured Gas Wells (existing wells)	REC	$400,508,928	-$26,181,572	264,115	1,810,245	19,189	$1,516	-$99
Conventional Gas Wells	Combustion	$149,164,257	$149,164,257	316	2,165	23	$472,227	$472,227
Oil Wells	Combustion	$138,711,979	$138,711,979	44	47	0	$3,134,431	$3,134,431
Equipment Leaks								
Well Pads	NSPS Subpart VV	$111,773,662	$104,412,154	10,646	38,287	401	$10,499	$9,808
Gathering and Boosting Stations	NSPS Subpart VV	$15,692,325	$14,072,850	2,340	8,415	88	$6,705	$6,013
Processing Plants	NSPS Subpart VVa	$1,309,650	$982,648	392	1,411	15	$3,343	$2,508
Transmission Compressor Stations	NSPS Subpart VV	$2,712,450	$2,712,450	261	9,427	8	$10,389	$10,389
Reciprocating Compressors								
Well Pads	Annual Monitoring/ Maintenance (AMM)	$22,204,209	$21,984,763	263	947	10	$84,379	$83,545
Gathering/Boosting Stations	AMM	$515,764	$182,597	400	1,437	15	$1,291	$457
Processing Plants	AMM	$436,806	-$465,354	1,082	3,892	41	$404	-$430
Transmission Compressor Stations	AMM	$47,892	$47,892	12	423	0	$4,093	$4,093
Underground Storage Facilities	AMM	$13,396	$13,396	2	87	0	$5,542	$5,542

Table 3-3 (continued) Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by Emissions Sources and Points, NSPS, 2015

Source/Emissions Point	Emissions Control	Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
		Without Addl. Revenues	With Addl. Revenues	VOC	Methane	HAP	Without Addl. Revenues	With Addl. Revenues
Centrifugal Compressors								
Processing Plants	Dry Seals/Route to Process or Control	$170,853	-$1,979,687	288	3,183	10	$593	-$6,874
Transmission Compressor Stations	Dry Seals/Route to Process or Control	$149,496	-$1,086,704	43	1,546	1	$3,495	-$25,405
Pneumatic Controllers -								
Oil and Gas Production	Low Bleed/Route to Process	$320,071	-$20,699,918	25,210	90,685	952	$13	-$821
Natural Gas Trans. and Storage	Low Bleed/Route to Process	$1,539	$1,539	6	212	0	$262	$262
Storage Vessels								
High Throughput	95% control	$4,411,587	$4,234,856	29,654	6,490	876	$149	$143
Low Throughput	95% control	$248,225,012	$238,280,976	6,838	1,497	202	$36,298	$34,844

Table 3-4 Estimated Engineering Compliance Costs, NSPS (2008$)

	Option 1	Option 2 (Proposed)	Option 3
Capital Costs	$337,803,930	$738,530,998	$1,143,984,622
Annualized Costs			
Without Revenues from Additional Natural Gas Product Recovery	$336,163,858	$737,982,436	$868,160,873
With Revenues from Additional Natural Gas Product Recovery	-$19,496,449	-$44,695,374	$76,502,080
VOC Reductions (tons per year)	270,695	535,201	548,449
Methane Reduction (tons per year)	1,574,498	3,386,154	3,442,283
HAP Reductions (tons per year)	17,442	36,645	37,142
VOC Reduction Cost-Effectiveness ($/ton without additional product revenues)	$1,241.86	$1,378.89	$1,582.94
VOC Reduction Cost-Effectiveness ($/ton with additional product revenues)	-$72.02	-$83.51	$139.49

Note: the VOC reduction cost-effectiveness estimate assumes there is no benefit to reducing methane and HAP, which is not the case. We however present the per ton costs of reducing the single pollutant for illustrative purposes. As product prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional product recovery is included. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. A $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million in 2008 dollars. The cost estimates for each regulatory option also include reporting and recordkeeping costs of $18,805,398.

As mentioned earlier, the single difference between Option 1 and the proposed Option 2 is the inclusion of RECs for recompletions of existing wells in Option 2. The implication of this inclusion in Option 2 is clear in Table 3-4, as the estimated engineering compliance costs without additional product revenue more than double and VOC emissions reductions also more than double. Meanwhile, the addition of equipment leaks standards in Option 3 increases engineering costs more than $400 million dollars in 2008 dollars, but only marginally increase estimates of emissions reductions of VOCs, methane, and HAPS.

As the price assumption is very influential on estimated impacts, we performed a simple sensitivity analysis of the influence of the assumed wellhead price paid to natural gas producers on the overall engineering costs estimate of the proposed NSPS. Figure 3-1 plots the annualized costs after revenues from natural gas product recovery have been incorporated (in millions of 2008 dollars) as a function of the assumed price of natural gas paid to producers at the wellhead

for the recovered natural gas (represented by the sloped, dotted line). The vertical solid lines in the figure represent the natural gas price assumed in the RIA ($4.00/Mcf) for 2015 and the 2015 forecast by EIA in the 2011 Annual Energy Outlook ($4.22/Mcf) in 2008 dollars.

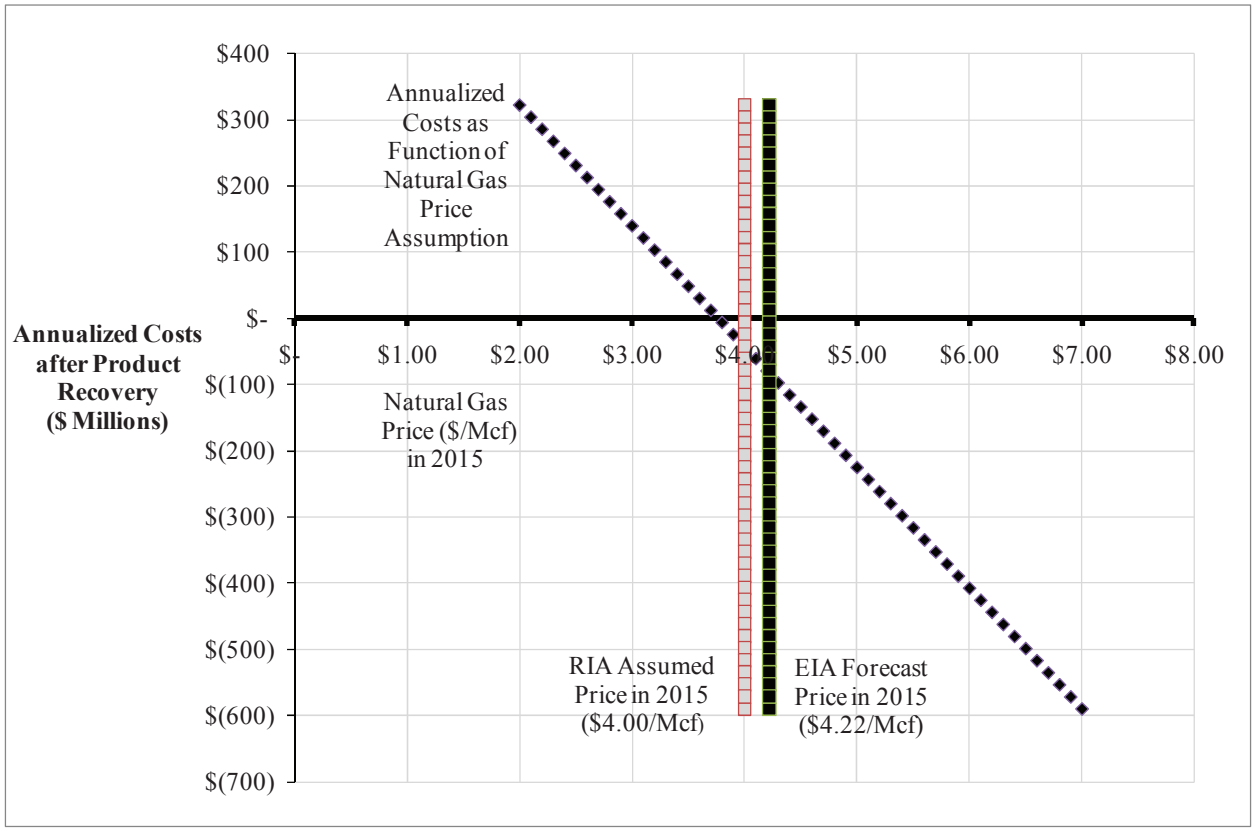


Figure 3-1 Sensitivity Analysis of Proposed NSPS Annualized Costs after Revenues from Additional Product Recovery are Included

As shown in Table 3-4, at the assumed $4/Mcf, the annualized costs are estimated at -$45 million. At $4.22/Mcf, the price forecast reported in the 2011 Annual Energy Outlook, the annualized costs are estimated at about -$90 million, which would approximately double the estimate of net cost savings of the proposed NSPS. As indicated by this difference, EPA has chosen a relatively conservative assumption (leading to an estimate of few savings and higher net costs) for the engineering costs analysis. The natural gas price at which the proposed NSPS breaks-even is around $3.77/Mcf. As mentioned earlier, a $1/Mcf change in the wellhead natural gas price leads to about a $180 million change in the annualized engineering costs of the proposed NSPS. Consequently, annualized engineering costs estimates would increase to about $140 million under a $3/Mcf price or decrease to about -$230 million under a $5/Mcf price.

It is additionally helpful to put the quantity of natural gas and condensate potentially recovered in the context of domestic production levels. To do so, it is necessary to make two adjustments. First, not all emissions reductions can be directed into production streams to be ultimately consumed by final consumers. Several controls require combustion of the natural gas rather than capture and direction into product streams. After adjusting estimates of national emissions reductions in Table 3-3 for these combustion-type controls, Options 1, 2, and 3 are estimated to capture about 83, 183, and 185 bcf of natural gas and 317,000, 726,000, and 726,000 barrels of condensate, respectively. For control options that are expected to recover natural gas products. Estimates of unit-level and nation-level product recovery are presented in Section 3 of the RIA. Note that completion-related requirements for new and existing wells generate all the condensate recovery for all NSPS regulatory options. For natural gas recovery, RECs contribute 77 bcf (92 percent) for Option 1, 176 bcf (97 percent) for Option 2, and 176 bcf (95 percent) for Option 3.

Table 3-5 Estimates of Control Unit-level and National Level Natural Gas and Condensate Recovery, NSPS Options, 2015

Source/ Emissions Points	Emissions Control	NSPS Option	Projected No. of Affected Units	Unit-level Product Recovery		Total Product Recovery	
				Natural Gas Savings (Mcf/unit)	Condensate (bbl/unit)	Natural Gas Savings (Mcf)	Condensate (bbl)
Well Completions							
Hydraulically Fractured Gas Wells	REC	1, 2, 3	9,313	8,258	34	76,905,813	316,657
Hydraulically Fractured Gas Wells	Combustion	1, 2, 3	446	0	0	0	0
Hydraulically Fractured Gas Wells (existing wells)	REC	2, 3	12,050	8,258	34	99,502,875	409,700
Equipment Leaks							
Well Pads	NSPS Subpart VV	3	4,774	386	0	1,840,377	0
Gathering and Boosting Stations	NSPS Subpart VV	3	275	1,472	0	404,869	0
Processing Plants	NSPS Subpart VVa	2, 3	29	2,819	0	81,750	0
Reciprocating Compressors							
Gathering/Boosting Stations	AMM	1, 2, 3	210	397	0	83,370	0
Processing Plants	AMM	1, 2, 3	375	1,079	0	404,677	0
Trans. Compressor Stations	AMM	1, 2, 3	199	1,122	0	223,374	0
Underground Storage Facilities	AMM	1, 2, 3	9	1,130	0	9,609	0
Centrifugal Compressors							
Processing Plants	Dry Seals/Route to Process or Ctrl	1, 2, 3	16	11,527	0	184,435	0
Trans. Compressor Stations	Dry Seals/Route to Process or Ctrl	1, 2, 3	14	5,716	0	80,018	0
Pneumatic Controllers -							
Oil and Gas Production	Low Bleed/Route to Process	1, 2, 3	13,632	386	0	5,254,997	0
Natural Gas Trans. and Storage	Low Bleed/Route to Process	1, 2, 3	67	0	0	0	0
Processing Plants	Instrument Air	1, 2, 3	15	871.0	0	13,064	0
Storage Vessels							
High Throughput	95% control	1, 2, 3	304	146	0	44,189	0
Option 1 Total (Mcf)						**83,203,546**	**316,657**
Option 2 Total (Mcf)						**182,788,172**	**726,357**
Option 3 Total (Mcf)						**185,033,417**	**726,357**

A second adjustment to the natural gas quantities is necessary to account for nonhydrocarbon gases removed and gas that reinjected to repressurize wells, vented or flared, or consumed in production processes. Generally, wellhead production is metered at or near the wellhead and payments to producers are based on these metered values. In most cases, the natural gas is minimally processed at the meter and still contains impurities or co-products that must be processed out of the natural gas at processing plants. This means that the engineering cost estimates of revenues from additional natural gas recovery arising from controls implemented at the wellhead include payment for the impurities, such as the VOC and HAP content of the unprocessed natural gas. According to EIA, in 2009 the gross withdrawal of natural gas totaled 26,013 bcf, but 20,580 bcf was ultimately considered dry production (these figures exclude EIA estimates of flared and vented natural gas). Using these numbers, we apply a factor of 0.79 (20,580 bcf divided by 26,013 bcf) to the adjusted sums in the previous paragraph to estimate the volume of gas that is captured by controls that may ultimately by consumed by final consumers.

After making these adjustments, we estimate that Option 1 will potentially recover approximately 66 bcf, proposed Option 2 will potentially recover about 145 bcf, and Option 3 will potentially recover 146 bcf of natural gas that will ultimately be consumed by natural gas consumers.[7] EIA forecasts that the domestic dry natural gas production in 2015 will be 20,080 bcf. Consequently, Option 1, proposed Option 2, and Option 3 may recover production representing about 0.29 percent, 0.64 percent and 0.65 percent of domestic dry natural gas production predicted in 2015, respectively. These estimates, however, do not account for adjustments producers might make, once compliance costs and potential revenues from additional natural gas recovery factor into economic decisionmaking. Also, as discussed in the previous paragraph, these estimates do not include the nonhydrocarbon gases removed, natural gas reinjected to repressurize wells, and natural gas consumed in production processes, and therefore will be lower than the estimates of the gross natural gas captured by implementing controls.

[7] To convert U.S. short tons of methane to a cubic foot measure, we use the conversion factor of 48.04 Mcf per U.S. short ton.

Clearly, this discussion raises the question as to why, if emissions can be reduced profitably using environmental controls, more producers are not adopting the controls in their own economic self-interest. This question is made clear when examining simple estimates of the rate of return to installing emissions controls that, using the engineering compliance costs estimates, the estimates of natural gas product recovery, and assumed product prices (Table 3-6). The rates of return presented in are for evaluated controls where estimated revenues from additional product recovery exceed the costs. The rate of return is calculated using the simple formula: product recovery, and assumed product prices (Table 3-6). The rates of return presented in are for evaluated controls where estimated revenues from additional product recovery exceed the costs. The rate of return is calculated using the simple formula:

$$\text{rate of return} = \left(\frac{\text{estimated revenues}}{\text{estimated costs}} - 1 \right) \times 100 .$$

Table 3-6 Simple Rate of Return Estimate for NSPS Control Options

Emission Point	Control Option	Rate of Return
New Completions of Hydraulically Fractured Wells	Reduced Emissions Completions	6.5%
Re-completions of Existing Hydraulically Fractured Wells	Reduced Emissions Completions	6.5%
Reciprocating Compressors (Processing Plants)	Replace Packing Every 3 Years of Operation	208.3%
Centrifugal Compressors (Processing Plants)	Convert to Dry Seals	1158.7%
Centrifugal Compressors (Transmission Compressor Stations)	Convert to Dry Seals	726.9%
Pneumatic Controllers (Oil and Gas Production)	Low Bleed	6467.3%
Overall Proposed NSPS	**Low Bleed**	**6.1%**

Note: The table presents only control options where estimated revenues from natural gas product recovery exceeds estimated annualized engineering costs

Recall from Table 2-23 in the Industry Profile, that EIA estimates an industry-level rate of return on investments for various segments of the oil and natural gas industry. While the numbers varies greatly over time because of industry and economic factors, EIA estimates a 10.7 percent rate of return on investments for oil and natural gas production in 2008. While this amount is higher than the 6.5 percent rate estimated for RECs, it is significantly lower than the rate of returns estimated for other controls anticipated to have net savings.

Assuming financially rational producers, standard economic theory suggests that all oil and natural gas firms would incorporate all cost-effective improvements, which they are aware

of, without government intervention. The cost analysis of this draft RIA nevertheless is based on the observation that emission reductions that appear to be profitable in our analysis have not been generally adopted. One possible explanation may be the difference between the average profit margin garnered by productive capital and the environmental capital where the primary motivation for installing environmental capital would be to mitigate the emission of pollutants and confer social benefits as discussed in Chapter 4.

Another explanation for why there appear to be negative cost control technologies that are not generally adopted is imperfect information. If emissions from the oil and natural gas sector are not well understood, firms may underestimate the potential financial returns to capturing emissions. Quantifying emissions is difficult and has been done in relatively few studies. Recently, however, advances in infrared imagery have made it possible to affordably visualize, if not quantify, methane emissions from any source using a handheld camera. This infrared camera has increased awareness within industry and among environmental groups and the public at large about the large number of emissions sources and possible scale of emissions from oil and natural gas production activities. Since, as discussed in the TSD chapter referenced above, 15 percent of new natural gas well completions with hydraulic fracturing and 15 percent of existing natural gas well recompletions with hydraulic fracturing are estimated to be controlled by either flare or REC in the baseline, it is unlikely that a lack of information will be a significant reason for these emission points to not be addressed in the absence of Federal regulation in 2015. However, for other emission points, a lack of information, or the cost associated with doing a feasibility study of potential emission capture technologies, may continue to prevent firms from adopting these improvements in the absence of regulation.

Another explanation is the cost associated with irreversibility associated with implementing these environmental controls are not reflected in the engineering cost estimates above. Due to the high volatility of natural gas prices, it is important to recognize the value of flexibility taken away from firms when requiring them to install and use a particular emissions capture technology. If a firm has not adopted the technology on its own, then a regulation mandating its use means the firm loses the option to postpone investment in the technology in order to pursue alternative investments today, and the option to suspend use of the technology if it becomes unprofitable in the future. Therefore, the full cost of the regulation to the firm is the

engineering cost and the lost option value minus the revenues from the sale of the additional recovered product. In the absence of quantitative estimates of this option value for each emission point affected by the NSPS and NESHAP improvements, the costs presented in this RIA may underestimate the full costs faced by the affected firms. With these caveats in mind, EPA believes it is analytically appropriate to analyze costs and economic impacts costs presented in Table 3-2 and Table 3-3 using the additional product recovery and associated revenues.

3.2.2.2 NESHAP Sources

As discussed in Section 3.2.1.2, EPA examined three emissions points as part of its analysis for the proposed NESHAP amendments. Unlike the controls for the proposed NSPS, the controls evaluated under the proposed NESHAP amendments do not direct significant quantities of natural gas that would otherwise be flared or vented into the production stream. Table 3-7 shows the projected number of controls required, estimated unit-level capital and annualized costs, and estimated total annualized costs. The table also shows estimated emissions reductions for HAPs, VOCs, and methane, as well as a cost-effectiveness estimate for HAP reduction, based upon engineering (not social) costs.

Table 3-7 Summary of Estimated Capital and Annual Costs, Emissions Reductions, and HAP Reduction Cost-Effectiveness for Proposed NESHAP Amendments

Source/Emissions Point	Projected No. of Controls Required	Capital Costs/ Unit (2008$)	Annualized Cost/Unit (2008$)	Total Annualized Cost (2008$)	Emission Reductions (tons per year) HAP	VOC	Methane	HAP Reduction Cost-Effectiveness (2008$/ton)
Production - Small Glycol Dehydrators	115	65,793	30,409	3,497,001	548	893	324	6,377
Transmission - Small Glycol Dehydrators	19	19,537	19,000	361,000	243	475	172	1,483
Storage Vessels	674	65,243	14,528	9,791,872	589	7,812	4,364	16,618
Reporting and Recordkeeping	---	196	2,933	2,369,755	---	---	---	---
Total	**808**			**16,019,871**	**1,381**	**9,243**	**4,859**	**10,576**

Note: Totals may not sum due to independent rounding.

Under the Proposed NESHAP Amendments, about 800 controls will be required, costing a total of $16.0 million (Table 3-7). We include reporting and recordkeeping costs as a unique line item showing these costs for the entire set of proposed amendments. These controls will reduce HAP emissions by about 1,400 tons, VOC emissions by about 9,200 tons, and methane by about 4,859 tons. The cost-per-ton to reduce HAP emissions is estimated at about $11,000 per ton. All figures are in 2008 dollars.

3.3 References

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Oil and Gas Journal. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010.

4 BENEFITS OF EMISSIONS REDUCTIONS

4.1 Introduction

The proposed Oil and Natural Gas NSPS and NESHAP amendments are expected to result in significant reductions in existing emissions and prevent new emissions from expansions of the industry. While we expect that these avoided emissions will result in improvements in air quality and reduce health effects associated with exposure to HAPs, ozone, and fine particulate matter ($PM_{2.5}$), we have determined that quantification of those health benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no health benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. For the proposed NSPS, the HAP and climate benefits can be considered "co-benefits", and for the proposed NESHAP amendments, the ozone and $PM_{2.5}$ health benefits and climate benefits can be considered "co-benefits". These co-benefits occur because the control technologies used to reduce VOC emissions also reduce emissions of HAPs and methane.

The proposed NSPS is anticipated to prevent 37,000 tons of HAPs, 540,000 tons of VOCs, and 3.4 million tons of methane from new sources, while the proposed NESHAP amendments is anticipated reduce 1,400 tons of HAPs, 9,200 tons of VOCs, and 4,900 tons of methane from existing sources. The specific control technologies for the proposed NSPS is also anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 2,800 tons of CO, 7.6 tons of PM, and 1,000 tons of THC, and proposed NESHAP is anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC. Both rules would have additional emission changes associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons for the proposed NSPS and 93 thousand metric tons for the proposed NESHAP. As described in the subsequent sections, these pollutants are associated with substantial health effects, welfare effects, and climate effects. With the data available, we are not able to provide a credible benefits estimates for any of these pollutants for these rules, due to the differences in the locations of oil and natural gas emission points relative to existing information, and the highly localized nature of air quality responses associated with HAP and VOC reductions. In addition, we do not yet have interagency agreed upon valuation estimates

for greenhouse gases other than CO_2 that could be used to value the climate co-benefits associated with avoiding methane emissions. Instead, we provide a qualitative assessment of the benefits and co-benefits as well as a break-even analysis in Chapter 6 of this RIA. A break-even analysis answers the question, "What would the benefits need to be for the benefits to exceed the costs." While a break-even approach is not equivalent to a benefits analysis, we feel the results are illustrative, particularly in the context of previous benefit per ton estimates.

4.2 Direct Emission Reductions from the Oil and Natural Gas Rules

As described in Section 2 of this RIA, oil and natural gas operations in the U.S. include a variety of emission points for VOCs and HAPs including wells, processing plants, compressor stations, storage equipment, and transmission and distribution lines. These emission points are located throughout much of the country with significant concentrations in particular regions. For example, wells and processing plants are largely concentrated in the South Central, Midwest, and Southern California regions of the U.S., whereas gas compression stations are located all over the country. Distribution lines to customers are frequently located within areas of high population density.

In implementing these rules, emission controls may lead to reductions in ambient $PM_{2.5}$ and ozone below the National Ambient Air Quality Standards (NAAQS) in some areas and assist other areas with attaining the NAAQS. Due to the high degree of variability in the responsiveness of ozone and $PM_{2.5}$ formation to VOC emission reductions, we are unable to determine how these rules might affect attainment status without air quality modeling data.[8] Because the NAAQS RIAs also calculate ozone and PM benefits, there are important differences worth noting in the design and analytical objectives of each RIA. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources. In short, NAAQS RIAs hypothesize, but do not predict, the control strategies that States may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. However,

[8] The responsiveness of ozone and $PM_{2.5}$ formation is discussed in greater detail in sections 4.4.1 and 4.5.1 of this RIA.

some costs and benefits estimated in this RIA account for the same air quality improvements as estimated in an illustrative NAAQS RIA.

By contrast, the emission reductions for this rule are from a specific class of well-characterized sources. In general, EPA is more confident in the magnitude and location of the emission reductions for these rules. It is important to note that emission reductions anticipated from these rules do not result in emission increases elsewhere (other than potential energy disbenefits). Emission reductions achieved under these and other promulgated rules will ultimately be reflected in the baseline of future NAAQS analyses, which would reduce the incremental costs and benefits associated with attaining the NAAQS. EPA remains forward looking towards the next iteration of the 5-year review cycle for the NAAQS, and as a result does not issue updated RIAs for existing NAAQS that retroactively update the baseline for NAAQS implementation. For more information on the relationship between the NAAQS and rules such as analyzed here, please see Section 1.2.4 of the SO_2 NAAQS RIA (U.S. EPA, 2010d). Table 4-1 shows the direct emission reductions anticipated for these rules by option. It is important to note that these benefits accrue at different spatial scales. HAP emission reductions reduce exposure to carcinogens and other toxic pollutants primarily near the emission source. Reducing VOC emissions would reduce precursors to secondary formation of $PM_{2.5}$ and ozone, which reduces exposure to these pollutants on a regional scale. Climate effects associated with long-lived greenhouse gases like methane are primarily at a global scale, but methane is also a precursor to ozone, a short-lived climate forcer that exhibits spatial and temporal variability.

Table 4-1 Direct Emission Reductions Associated with Options for the Oil and Natural Gas NSPS and NESHAP amendments in 2015 (short tons per year)

Pollutant	NESHAP Amendments	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3
HAPs	1,381	17,442	36,645	37,142
VOCs	9,243	270,695	535,201	548,449
Methane	4,859	1,574,498	3,386,154	3,442,283

4.3 Secondary Impacts Analysis for Oil and Gas Rules

The control techniques to avert leaks and vents of VOCs and HAPs are associated with several types of secondary impacts, which may partially offset the direct benefits of this rule. In this RIA, we refer to the secondary impacts associated with the specific control techniques as "producer-side" impacts.[9] For example, by combusting VOCs and HAPs, combustion increases emissions of carbon monoxide, NOx, particulate matter and other pollutants. In addition to "producer-side" impacts, these control techniques would also allow additional natural gas recovery, which would contribute to additional combustion of the recovered natural gas and ultimately a shift in the national fuel mix. We refer to the secondary impacts associated with the combustion of the recovered natural gas as "consumer-side" secondary impacts. We provide a conceptual diagram of both categories of secondary impacts in Figure 4-1.

[9] In previous RIAs, we have also referred to these impacts as energy disbenefits.

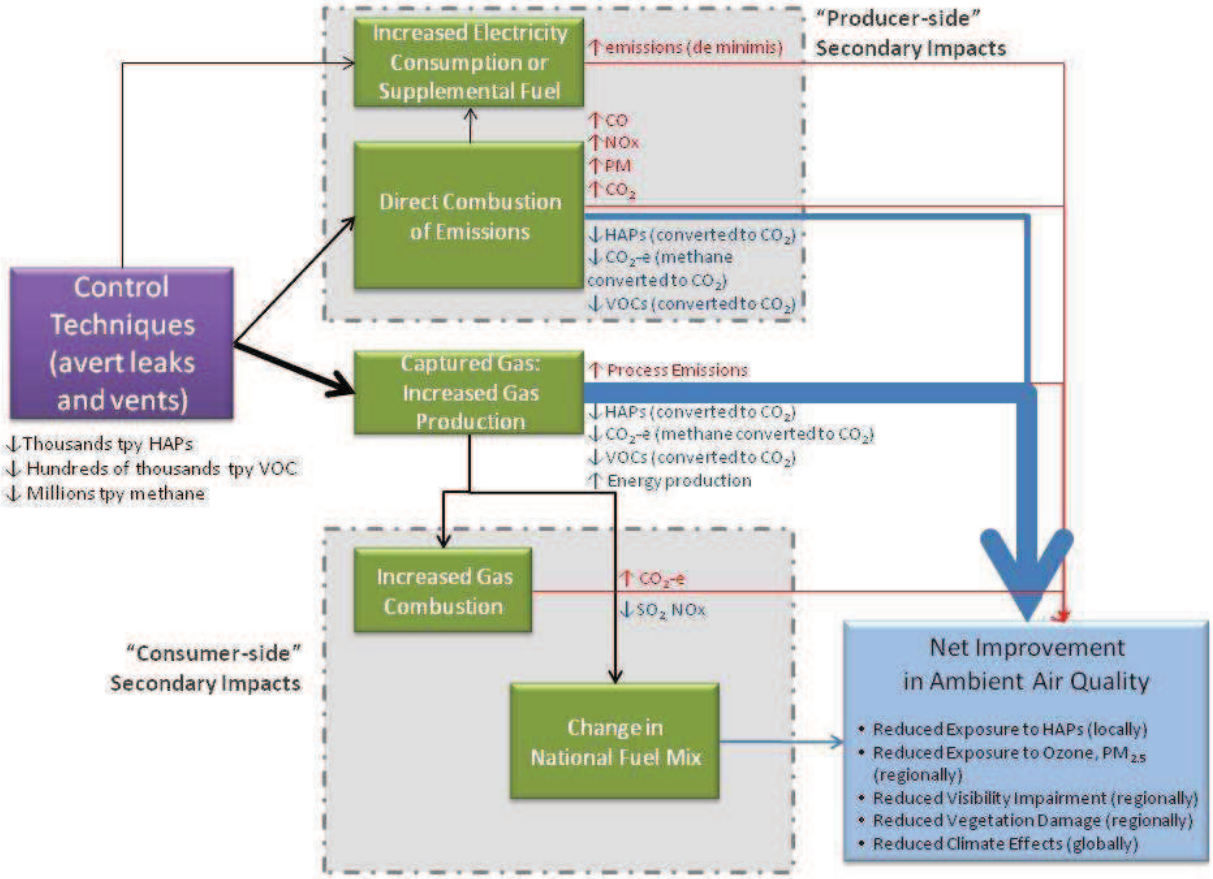


Figure 4-1 Conceptual Diagram of Secondary Impacts from Oil and Gas NSPS and NESHAP Amendments

Table 4-2 shows the estimated secondary impacts for the selected option for the "producer-side" impacts. Relative to the direct emission reductions anticipated from these rules, the magnitude of these secondary air pollutant impacts is small. Because the geographic distribution of these emissions from the oil and gas sector is not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009), we are unable to monetize the $PM_{2.5}$ disbenefits associated with the producer-side secondary impacts. In addition, it is not appropriate to monetize the disbenefits associated with the increased CO_2 emissions without monetizing the averted methane emissions because the overall global warming potential (GWP) is actually

lower. Through the combustion process, methane emissions are converted to CO_2 emissions, which have 21 times less global warming potential compared to methane (IPCC, 2007).[10]

Table 4-2 Secondary Air Pollutant Impacts Associated with Control Techniques by Emissions Category ("Producer-Side") (tons per year)

Emissions Category	CO_2	NOx	PM	CO	THC
Completions of New Wells (NSPS)	587,991	302	5	1,644	622
Recompletions of Existing Wells (NSPS)	398,341	205	-	1,114	422
Pneumatic Controllers (NSPS)	22	1.0	2.6	-	-
Storage Vessels (NSPS)	856	0.5	0.0	2.4	0.9
Total NSPS	**987,210**	**508**	**7.6**	**2,760**	**1,045**
Total NESHAP (Storage Vessels)	**5,543**	**2.9**	**0.1**	**16**	**6**

For the "consumer-side" impacts associated with the NSPS, we modeled the impact of the regulatory options on the national fuel mix and associated CO_2-equivalent emissions (Table 4-3).[11] We provide the modeled results of the "consumer-side" CO_2-equivalent emissions in Table 7-12Error! Reference source not found.

The modeled results indicate that through a slight shift in the national fuel mix, the CO_2-equivalent emissions across the energy sector would increase by 1.6 million metric tons for the proposed NSPS option in 2015. This is in addition to the other secondary impacts and directly avoided emissions, for a total 62 million metric tons of CO_2-equivalent emissions averted as shown in Table 4-4. Due to time limitations under the court-ordered schedule, we did not estimate the other emissions (e.g., NOx, PM, SOx) associated with the additional national gas consumption or the change in the national fuel mix.

[10] This issue is discussed in more detail in Section 4.7 of this RIA.
[11] A full discussion of the energy modeling is available in Section 7 of this RIA.

Table 4-3 Modeled Changes in Energy-related CO_2-equivalent Emissions by Fuel Type for the Proposed Oil and Gas NSPS in 2015 (million metric tons) ("Consumer-Side")[1]

Fuel Type	NSPS Option 1 (million metric tons change in CO_2-e)	NSPS Option 2 (million metric tons change in CO_2-e) (Proposed)	NSPS Option 3 (million metric tons change in CO_2-e)
Petroleum	-0.51	-0.14	-0.18
Natural Gas	2.63	1.35	1.03
Coal	-3.04	0.36	0.42
Other	0.00	0.00	0.00
Total modeled Change in CO_2-e Emissions	**-0.92**	**1.57**	**1.27**

[1] These estimates reflect the modeled change in CO_2-e emissions using NEMS shown in Table 7-12. Totals may not sum due to independent rounding.

Table 4-4 Total Change in CO_2-equivalent Emissions including Secondary Impacts for the Proposed Oil and Gas NSPS in 2015 (million metric tons)

Emissions Source	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP Amendments
Averted CO_2-e Emissions from New Sources[1]	-30.00	-64.51	-65.58	-0.09
Additional CO_2-e Emissions from Combustion and Supplemental Energy (Producer-side)[2]	0.90	0.90	0.90	0.01
Total Modeled Change in Energy-related CO_2-e Emissions (Consumer-side)[3]	-0.92	1.57	1.27	--
Total Change in CO_2-e Emissions after Adjustment for Secondary Impacts	**-30.02**	**-62.04**	**-63.41**	**-0.09**

[1] This estimate reflects the GWP of the avoided methane emissions from new sources shown in Table 4-1 and has been converted from short tons to metric tons.

[2] This estimate represents the secondary producer-side impacts associated with additional CO_2 emissions from combustion and from additional electricity requirements shown in Table 4-2 and has been converted from short tons to metric tons. We use the producer-side secondary impacts associated with the proposed NSPS option as a surrogate for the impacts of the other options.

[3]This estimate reflects the modeled change in the energy–related consumer-side impacts shown in Table 4-3.

Totals may not sum due to independent rounding.

Based on these analyses, the net impact of both the direct and secondary impacts of these rules would be an improvement in ambient air quality, which would reduce exposure to various harmful pollutants, improve visibility impairment, reduce vegetation damage, and reduce potency of greenhouse gas emissions. Table 4-5 provides a summary of the direct and secondary emissions changes for each option.

Table 4-5 Summary of Emissions Changes for the Proposed Oil and Gas NSPS and NESHAP in 2015 (short tons per year)

	Pollutant	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP
Change in Direct Emissions	VOC	-270,000	-540,000	-550,000	-9,200
	Methane	-1,600,000	-3,400,000	-3,400,000	-4,900
	HAP	-17,000	-37,000	-37,000	-1,400
Change in Secondary Emissions (Producer-Side) [1]	CO_2	990,000	990,000	990,000	5,500
	NOx	510	510	510	2.9
	PM	7.6	7.6	7.6	0.1
	CO	2,800	2,800	2,800	16
	THC	1,000	1,000	1,000	6.0
Change in Secondary Emissions (Consumer-Side)	CO_2-e	-1,000,000	1,700,000	1,400,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e	-33,000,000	-68,000,000	-70,000,000	-96,000

[1] We use the producer-side secondary impacts associated with the proposed option as a surrogate for the impacts of the other options. Totals may not sum due to independent rounding.

4.4 Hazardous Air Pollutant (HAP) Benefits

Even though emissions of air toxics from all sources in the U.S. declined by approximately 42 percent since 1990, the 2005 National-Scale Air Toxics Assessment (NATA) predicts that most Americans are exposed to ambient concentrations of air toxics at levels that have the potential to cause adverse health effects (U.S. EPA, 2011d).[12] The levels of air toxics to which people are exposed vary depending on where people live and work and the kinds of activities in which they engage. In order to identify and prioritize air toxics, emission source types and locations that are of greatest potential concern, U.S. EPA conducts the NATA.[13] The most recent NATA was conducted for calendar year 2005 and was released in March 2011. NATA includes four steps:

[12] The 2005 NATA is available on the Internet at http://www.epa.gov/ttn/atw/nata2005/.

[13] The NATA modeling framework has a number of limitations that prevent its use as the sole basis for setting regulatory standards. These limitations and uncertainties are discussed on the 2005 NATA website. Even so, this modeling framework is very useful in identifying air toxic pollutants and sources of greatest concern, setting regulatory priorities, and informing the decision making process. U.S. EPA. (2011) 2005 National-Scale Air Toxics Assessment. http://www.epa.gov/ttn/atw/nata2005/

1) Compiling a national emissions inventory of air toxics emissions from outdoor sources

2) Estimating ambient and exposure concentrations of air toxics across the United States

3) Estimating population exposures across the United States

4) Characterizing potential public health risk due to inhalation of air toxics including both cancer and noncancer effects

Based on the 2005 NATA, EPA estimates that about 5 percent of census tracts nationwide have increased cancer risks greater than 100 in a million. The average national cancer risk is about 50 in a million. Nationwide, the key pollutants that contribute most to the overall cancer risks are formaldehyde and benzene.[14,15] Secondary formation (e.g., formaldehyde forming from other emitted pollutants) was the largest contributor to cancer risks, while stationary, mobile and background sources contribute almost equal portions of the remaining cancer risk.

Noncancer health effects can result from chronic,[16] subchronic,[17] or acute[18] inhalation exposures to air toxics, and include neurological, cardiovascular, liver, kidney, and respiratory effects as well as effects on the immune and reproductive systems. According to the 2005 NATA, about three-fourths of the U.S. population was exposed to an average chronic concentration of air toxics that has the potential for adverse noncancer respiratory health effects. Results from the 2005 NATA indicate that acrolein is the primary driver for noncancer respiratory risk.

[14] Details on EPA's approach to characterization of cancer risks and uncertainties associated with the 2005 NATA risk estimates can be found at http://www.epa.gov/ttn/atw/nata1999/riskbg.html#Z2.

[15] Details about the overall confidence of certainty ranking of the individual pieces of NATA assessments including both quantitative (e.g., model-to-monitor ratios) and qualitative (e.g., quality of data, review of emission inventories) judgments can be found at http://www.epa.gov/ttn/atw/nata/roy/page16.html.

[16] Chronic exposure is defined in the glossary of the Integrated Risk Information (IRIS) database (http://www.epa.gov/iris) as repeated exposure by the oral, dermal, or inhalation route for more than approximately 10% of the life span in humans (more than approximately 90 days to 2 years in typically used laboratory animal species).

[17] Defined in the IRIS database as repeated exposure by the oral, dermal, or inhalation route for more than 30 days, up to approximately 10% of the life span in humans (more than 30 days up to approximately 90 days in typically used laboratory animal species).

[18] Defined in the IRIS database as exposure by the oral, dermal, or inhalation route for 24 hours or less.

Figure 4-2 and Figure 4-3 depict the estimated census tract-level carcinogenic risk and noncancer respiratory hazard from the assessment. It is important to note that large reductions in HAP emissions may not necessarily translate into significant reductions in health risk because toxicity varies by pollutant, and exposures may or may not exceed levels of concern. For example, acetaldehyde mass emissions are more than double acrolein emissions on a national basis, according to EPA's 2005 National Emissions Inventory (NEI). However, the Integrated Risk Information System (IRIS) reference concentration (RfC) for acrolein is considerably lower than that for acetaldehyde, suggesting that acrolein could be potentially more toxic than acetaldehyde.[19] Thus, it is important to account for the toxicity and exposure, as well as the mass of the targeted emissions.

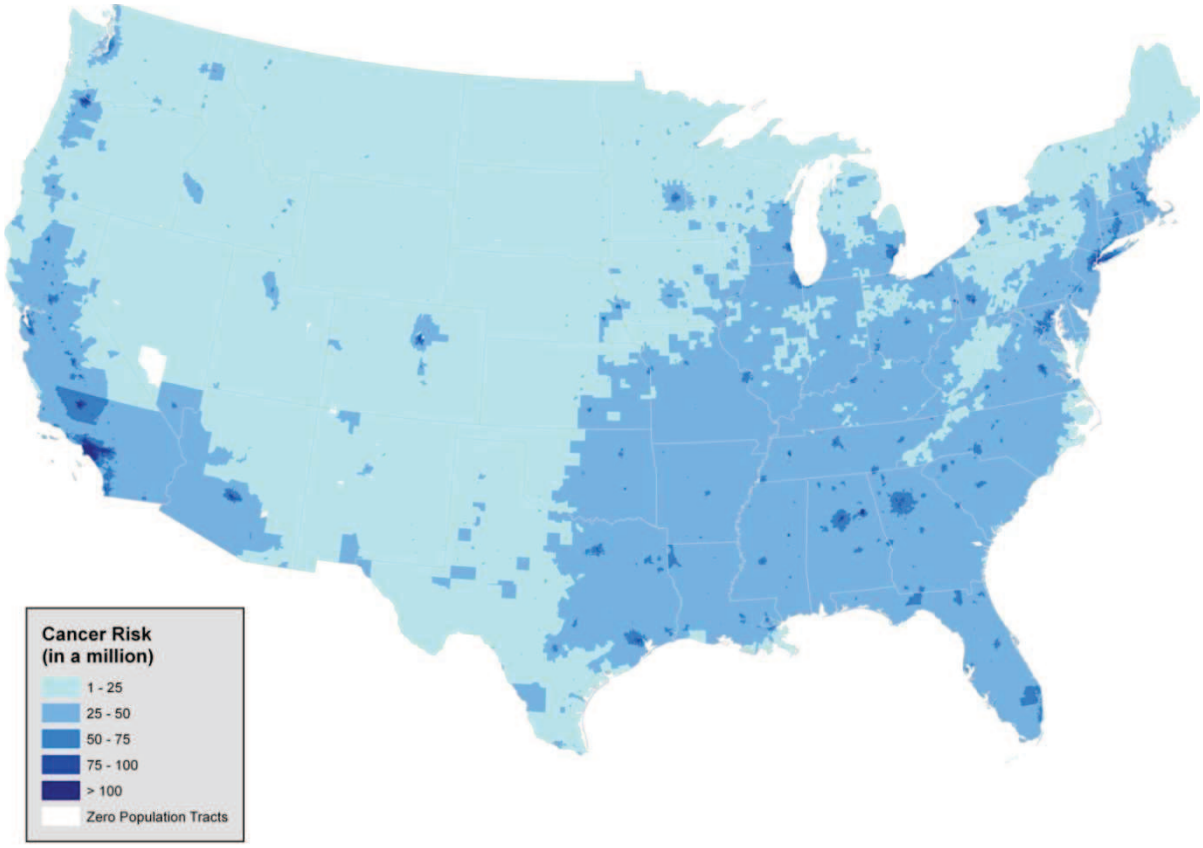


Figure 4-2 Estimated Chronic Census Tract Carcinogenic Risk from HAP exposure from outdoor sources (2005 NATA)

[19] Details on the derivation of IRIS values and available supporting documentation for individual chemicals (as well as chemical values comparisons) can be found at http://cfpub.epa.gov/ncea/iris/compare.cfm.

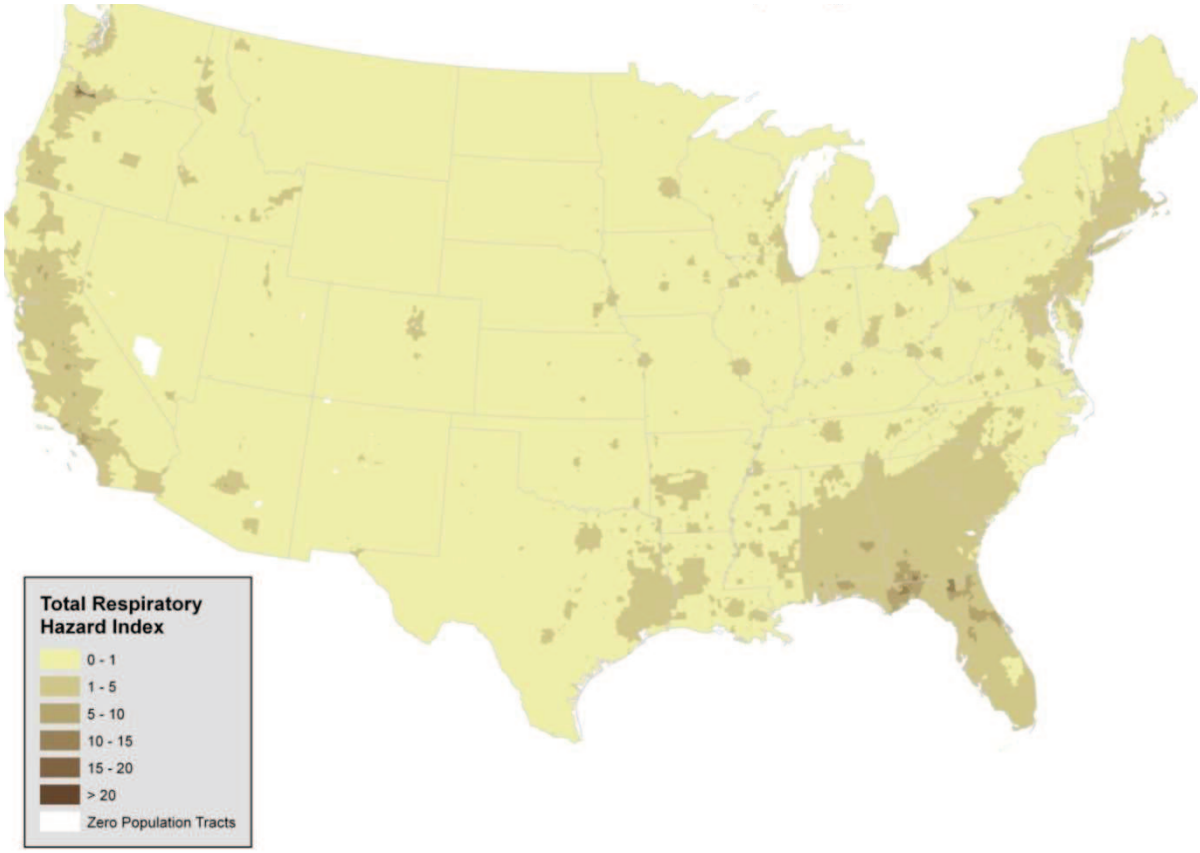


Figure 4-3 Estimated Chronic Census Tract Noncancer (Respiratory) Risk from HAP exposure from outdoor sources (2005 NATA)

Due to methodology and data limitations, we were unable to estimate the benefits associated with the hazardous air pollutants that would be reduced as a result of these rules.. In a few previous analyses of the benefits of reductions in HAPs, EPA has quantified the benefits of potential reductions in the incidences of cancer and non-cancer risk (e.g., U.S. EPA, 1995). In those analyses, EPA relied on unit risk factors (URF) developed through risk assessment procedures.[20] These URFs are designed to be conservative, and as such, are more likely to represent the high end of the distribution of risk rather than a best or most likely estimate of risk. As the purpose of a benefit analysis is to describe the benefits most likely to occur from a reduction in pollution, use of high-end, conservative risk estimates would overestimate the

[20]The unit risk factor is a quantitative estimate of the carcinogenic potency of a pollutant, often expressed as the probability of contracting cancer from a 70-year lifetime continuous exposure to a concentration of one $\mu g/m^3$ of a pollutant.

benefits of the regulation. While we used high-end risk estimates in past analyses, advice from the EPA's Science Advisory Board (SAB) recommended that we avoid using high-end estimates in benefit analyses (U.S. EPA-SAB, 2002). Since this time, EPA has continued to develop better methods for analyzing the benefits of reductions in HAPs.

As part of the second prospective analysis of the benefits and costs of the Clean Air Act (U.S. EPA, 2011a), EPA conducted a case study analysis of the health effects associated with reducing exposure to benzene in Houston from implementation of the Clean Air Act (IEc, 2009). While reviewing the draft report, EPA's Advisory Council on Clean Air Compliance Analysis concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAPs) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (U.S. EPA-SAB, 2008).

In 2009, EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAPs. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn et al., 2011).

In summary, monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAPs, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAPs in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAPs anticipated to be reduced by these rules and we summarize the results of the residual risk assessment for the Risk and Technology Review (RTR). EPA remains committed to improving methods for estimating HAP benefits by continuing to explore additional concepts of benefits, including changes in the distribution of risk.

Available emissions data show that several different HAPs are emitted from oil and natural gas operations, either from equipment leaks, processing, compressing, transmission and distribution, or storage tanks. Emissions of eight HAPs make up a large percentage the total

HAP emissions by mass from the oil and gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2011a). In the subsequent sections, we describe the health effects associated with the main HAPs of concern from the oil and natural gas sector: benzene, toluene, carbonyl sulfide, ethyl benzene, mixed xylenes, and n-hexane. These rules combined are anticipated to avoid or reduce 58,000 tons of HAPs per year. With the data available, it was not possible to estimate the tons of each individual HAP that would be reduced.

EPA conducted a residual risk assessment for the NESHAP rule (U.S. EPA, 2011c). The results for oil and gas production indicate that maximum lifetime individual cancer risks could be 30 in-a-million for existing sources before and after controls with a cancer incidence of 0.02 before and after controls. For existing natural gas transmission and storage, the maximum individual cancer risk decreases from 90-in-a-million before controls to 20-in-a-million after controls with a cancer incidence that decreases from 0.001 before controls to 0.0002 after controls. Benzene is the primary cancer risk driver. The results also indicate that significant noncancer impacts from existing sources are unlikely, especially after controls. EPA did not conduct a risk assessment for new sources affected by the NSPS. However, it is important to note that the magnitude of the HAP emissions avoided by new sources with the NSPS are more than an order of magnitude higher than the HAP emissions reduced from existing sources with the NESHAP.

4.4.1 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.[21,22,23] EPA states in its IRIS database that data indicate a causal

[21] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0276.htm.

[22] International Agency for Research on Cancer, IARC monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, International Agency for Research on Cancer, World Health Organization, Lyon, France, p. 345-389, 1982.

[23] Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. (1992) Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691-3695.

relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human Services (DHHS) has characterized benzene as a known human carcinogen.[24,25] A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[26,27] The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[28,29] In addition, recent work, including studies sponsored by the Health Effects Institute (HEI), provides evidence that biochemical responses are occurring at lower levels of benzene exposure than previously known.[30,31,32,33] EPA's IRIS program has not yet evaluated these new data.

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[24] International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

[25] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: http://ntp.niehs.nih.gov/go/16183.

[26] Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. Environ. Health Perspect. 82: 193-197.

[27] Goldstein, B.D. (1988). Benzene toxicity. Occupational medicine. State of the Art Reviews. 3: 541-554.

[28] Rothman, N., G.L. Li, M. Dosemeci, W.E. Bechtold, G.E. Marti, Y.Z. Wang, M. Linet, L.Q. Xi, W. Lu, M.T. Smith, N. Titenko-Holland, L.P. Zhang, W. Blot, S.N. Yin, and R.B. Hayes (1996) Hematotoxicity among Chinese workers heavily exposed to benzene. Am. J. Ind. Med. 29: 236-246.

[29] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene (Noncancer Effects). Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0276.htm.

[30] Qu, O.; Shore, R.; Li, G.; Jin, X.; Chen, C.L.; Cohen, B.; Melikian, A.; Eastmond, D.; Rappaport, S.; Li, H.; Rupa, D.; Suramaya, R.; Songnian, W.; Huifant, Y.; Meng, M.; Winnik, M.; Kwok, E.; Li, Y.; Mu, R.; Xu, B.; Zhang, X.; Li, K. (2003). HEI Report 115, Validation & Evaluation of Biomarkers in Workers Exposed to Benzene in China.

[31] Qu, Q., R. Shore, G. Li, X. Jin, L.C. Chen, B. Cohen, et al. (2002). Hematological changes among Chinese workers with a broad range of benzene exposures. Am. J. Industr. Med. 42: 275-285.

[32] Lan, Qing, Zhang, L., Li, G., Vermeulen, R., et al. (2004). Hematotoxically in Workers Exposed to Low Levels of Benzene. Science 306: 1774-1776.

[33] Turtletaub, K.W. and Mani, C. (2003). Benzene metabolism in rodents at doses relevant to human exposure from Urban Air. Research Reports Health Effect Inst. Report No.113.

4.4.2 Toluene[34]

Under the 2005 Guidelines for Carcinogen Risk Assessment, there is inadequate information to assess the carcinogenic potential of toluene because studies of humans chronically exposed to toluene are inconclusive, toluene was not carcinogenic in adequate inhalation cancer bioassays of rats and mice exposed for life, and increased incidences of mammary cancer and leukemia were reported in a lifetime rat oral bioassay.

The central nervous system (CNS) is the primary target for toluene toxicity in both humans and animals for acute and chronic exposures. CNS dysfunction (which is often reversible) and narcosis have been frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation: symptoms include fatigue, sleepiness, headaches, and nausea. Central nervous system depression has been reported to occur in chronic abusers exposed to high levels of toluene. Symptoms include ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision. Chronic inhalation exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep.

Human studies have also reported developmental effects, such as CNS dysfunction, attention deficits, and minor craniofacial and limb anomalies, in the children of women who abused toluene during pregnancy. A substantial database examining the effects of toluene in subchronic and chronic occupationally exposed humans exists. The weight of evidence from these studies indicates neurological effects (i.e., impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

4.4.3 Carbonyl sulfide

Limited information is available on the health effects of carbonyl sulfide. Acute (short-term) inhalation of high concentrations of carbonyl sulfide may cause narcotic effects and irritate

[34] All health effects language for this section came from: U.S. EPA. 2005. "Full IRIS Summary for Toluene (CASRN 108-88-3)" Environmental Protection Agency, Integrated Risk Information System (IRIS), Office of Health and Environmental Assessment, Environmental Criteria and Assessment Office, Cincinnati, OH. Available on the Internet at <http://www.epa.gov/iris/subst/0118.htm>.

the eyes and skin in humans.[35] No information is available on the chronic (long-term), reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl sulfide has not undergone a complete evaluation and determination under U.S. EPA's IRIS program for evidence of human carcinogenic potential.[36]

4.4.4 Ethylbenzene

Ethylbenzene is a major industrial chemical produced by alkylation of benzene. The pure chemical is used almost exclusively for styrene production. It is also a constituent of crude petroleum and is found in gasoline and diesel fuels. Acute (short-term) exposure to ethylbenzene in humans results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic (long-term) exposure of humans to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood. Animal studies have reported effects on the blood, liver, and kidneys and endocrine system from chronic inhalation exposure to ethylbenzene. No information is available on the developmental or reproductive effects of ethylbenzene in humans, but animal studies have reported developmental effects, including birth defects in animals exposed via inhalation. Studies in rodents reported increases in the percentage of animals with tumors of the nasal and oral cavities in male and female rats exposed to ethylbenzene via the oral route.[37,38] The reports of these studies lacked detailed information on the incidence of specific tumors, statistical analysis, survival data, and information on historical controls, thus the results of these studies were considered inconclusive by the International Agency for Research on Cancer (IARC, 2000) and the National Toxicology Program (NTP).[39,40] The NTP (1999) carried out a chronic inhalation

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[35] Hazardous Substances Data Bank (HSDB), online database). US National Library of Medicine, Toxicology Data Network, available online at http://toxnet.nlm.nih.gov/. Carbonyl health effects summary available at http://toxnet.nlm.nih.gov/cgi-bin/sis/search/r?dbs+hsdb:@term+@rn+@rel+463-58-1.

[36] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Carbonyl Sulfide. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0617.htm.

[37] Maltoni C, Conti B, Giuliano C and Belpoggi F, 1985. Experimental studies on benzene carcinogenicity at the Bologna Institute of Oncology: Current results and ongoing research. Am J Ind Med 7:415-446.

[38] Maltoni C, Ciliberti A, Pinto C, Soffritti M, Belpoggi F and Menarini L, 1997. Results of long-term experimental carcinogenicity studies of the effects of gasoline, correlated fuels, and major gasoline aromatics on rats. Annals NY Acad Sci 837:15-52.

[39] International Agency for Research on Cancer (IARC), 2000. Monographs on the Evaluation of Carcinogenic Risks to Humans. Some Industrial Chemicals. Vol. 77, p. 227-266. IARC, Lyon, France.

bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in male rats and renal tubule adenoma in females. NTP (1999) also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma in female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies.

4.4.5 Mixed xylenes

Short-term inhalation of mixed xylenes (a mixture of three closely-related compounds) in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects.[41] Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys.[42] Long-term inhalation exposure to xylenes in humans has been associated with a number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination.[43] EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

4.4.6 n-Hexane

The studies available in both humans and animals indicate that the nervous system is the primary target of toxicity upon exposure of n-hexane via inhalation. There are no data in humans and very limited information in animals about the potential effects of n-hexane via the oral route. Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central

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[40] National Toxicology Program (NTP), 1999. Toxicology and Carcinogenesis Studies of Ethylbenzene (CAS No. 100-41-4) in F344/N Rats and in B6C3F1 Mice (Inhalation Studies). Technical Report Series No. 466. NIH Publication No. 99-3956. U.S. Department of Health and Human Services, Public Health Service, National Institutes of Health. NTP, Research Triangle Park, NC.

[41] U.S. Environmental Protection Agency (U.S. EPA). 2003. Integrated Risk Information System File for Mixed Xylenes. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0270.htm.

[42] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53.

[43] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53.

nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral effects, neurophysiological changes and neuropathological effects upon inhalation exposure to n-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005), the database for n-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.[44]

4.4.7 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected by these rules, including hydrogen sulfide (H_2S). Information regarding the health effects of those compounds can be found in EPA's IRIS database.[45]

4.5 VOCs

4.5.1 VOCs as a PM2.5 precursor

This rulemaking would reduce emissions of VOCs, which are a precursor to $PM_{2.5}$. Most VOCs emitted are oxidized to carbon dioxide (CO_2) rather than to PM, but a portion of VOC emission contributes to ambient $PM_{2.5}$ levels as organic carbon aerosols (U.S. EPA, 2009a). Therefore, reducing these emissions would reduce $PM_{2.5}$ formation, human exposure to $PM_{2.5}$, and the incidence of $PM_{2.5}$-related health effects. However, we have not quantified the $PM_{2.5}$-related benefits in this analysis. Analysis of organic carbon measurements suggest only a fraction of secondarily formed organic carbon aerosols are of anthropogenic origin. The current state of the science of secondary organic carbon aerosol formation indicates that anthropogenic VOC contribution to secondary organic carbon aerosol is often lower than the biogenic (natural) contribution. Given that a fraction of secondarily formed organic carbon aerosols is from anthropogenic VOC emissions and the extremely small amount of VOC emissions from this sector relative to the entire VOC inventory it is unlikely this sector has a large contribution to

[44] U.S. EPA. 2005. Guidelines for Carcinogen Risk Assessment. EPA/630/P-03/001B. Risk Assessment Forum, Washington, DC. March. Available on the Internet at <http://www.epa.gov/ttn/atw/cancer_guidelines_final_3-25-05.pdf>.

[45] U.S. EPA Integrated Risk Information System (IRIS) database is available at: www.epa.gov/iris

ambient secondary organic carbon aerosols. Photochemical models typically estimate secondary organic carbon from anthropogenic VOC emissions to be less than 0.1 $\mu g/m^3$.

Due to time limitations under the court-ordered schedule, we were unable to perform air quality modeling for this rule. Due to the high degree of variability in the responsiveness of $PM_{2.5}$ formation to VOC emission reductions, we are unable to estimate the effect that reducing VOCs will have on ambient $PM_{2.5}$ levels without air quality modeling.

4.5.2 $PM_{2.5}$ health effects and valuation

Reducing VOC emissions would reduce $PM_{2.5}$ formation, human exposure, and the incidence of $PM_{2.5}$-related health effects. Reducing exposure to $PM_{2.5}$ is associated with significant human health benefits, including avoiding mortality and respiratory morbidity. Researchers have associated $PM_{2.5}$- exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009a). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to $PM_{2.5}$ (e.g., U.S. EPA (2010c)). These health effects include premature mortality for adults and infants, cardiovascular morbidity such as heart attacks, hospital admissions, and respiratory morbidity such as asthma attacks, acute and chronic bronchitis, hospital and ER visits, work loss days, restricted activity days, and respiratory symptoms. Although EPA has not quantified these effects in previous benefits analyses, the scientific literature suggests that exposure to $PM_{2.5}$ is also associated with adverse effects on birth weight, pre-term births, pulmonary function, other cardiovascular effects, and other respiratory effects (U.S. EPA, 2009a).

EPA assumes that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type (U.S. EPA, 2009a). Based on our review of the current body of scientific literature, EPA estimates PM-related mortality without applying an assumed concentration threshold. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels of $PM_{2.5}$ in the underlying epidemiology studies.

Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with effect that those emissions have on ambient $PM_{2.5}$ levels and the health effects associated with $PM_{2.5}$ exposure (Fann, Fulcher, and Hubbell, 2009). Using the estimates in Fann, Fulcher, and Hubbell (2009), the monetized benefit-per-ton of reducing VOC emissions in nine urban areas of the U.S. ranges from $560 in Seattle, WA to $5,700 in San Joaquin, CA, with a national average of $2,400. These estimates assume a 50 percent reduction in VOCs, the Laden et al. (2006) mortality function (based on the Harvard Six City Study, a large cohort epidemiology study in the Eastern U.S.), an analysis year of 2015, and a 3 percent discount rate.

Based on the methodology from Fann, Fulcher, and Hubbell (2009), we converted their estimates to 2008$ and applied EPA's current VSL estimate.[46] After these adjustments, the range of values increases to $680 to $7,000 per ton of VOC reduced for Laden et al. (2006). Using alternate assumptions regarding the relationship between $PM_{2.5}$ exposure and premature mortality from empirical studies and supplied by experts (Pope et al., 2002; Laden et al., 2006; Roman et al., 2008), additional benefit-per-ton estimates are available from this dataset, as shown in Table 4-6. EPA generally presents a range of benefits estimates derived from Pope et al. (2002) to Laden et al. (2006) because they are both well-designed and peer reviewed studies, and EPA provides the benefit estimates derived from expert opinions in Roman et al. (2008) as a characterization of uncertainty. In addition to the range of benefits based on epidemiology studies, this study also provided a range of benefits associated with reducing emissions in eight specific urban areas. The range of VOC benefits that reflects the adjustments as well as the range of epidemiology studies and the range of the urban areas is $280 to $7,000 per ton of VOC reduced.

While these ranges of benefit-per-ton estimates provide useful context for the break-even analysis, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship

[46] For more information regarding EPA's current VSL estimate, please see Section 5.4.4.1 of the RIA for the proposed Federal Transport Rule (U.S. EPA, 2010a). EPA continues to work to update its guidance on valuing mortality risk reductions.

between VOC emissions and $PM_{2.5}$, these factors lead us to conclude that the available VOC benefit per ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

Table 4-6 Monetized Benefits-per-Ton Estimates for VOCs (2008$)

Area	Pope et al.	Laden et al.	Expert A	Expert B	Expert C	Expert D	Expert E	Expert F	Expert G	Expert H	Expert I	Expert J	Expert K	Expert L
Atlanta	$620	$1,500	$1,600	$1,200	$1,200	$860	$2,000	$1,100	$730	$920	$1,200	$980	$250	$940
Chicago	$1,500	$3,800	$4,000	$3,100	$3,000	$2,200	$4,900	$2,800	$1,800	$2,300	$3,000	$2,500	$600	$2,400
Dallas	$300	$740	$780	$610	$590	$420	$960	$540	$360	$450	$590	$480	$120	$460
Denver	$720	$1,800	$1,800	$1,400	$1,400	$1,000	$2,300	$1,300	$850	$1,100	$1,400	$1,100	$280	$850
NYC/ Philadelphia	$2,100	$5,200	$5,500	$4,300	$4,200	$3,000	$6,900	$3,900	$2,500	$3,200	$4,200	$3,400	$830	$3,100
Phoenix	$1,000	$2,500	$2,600	$2,000	$2,000	$1,400	$3,300	$1,800	$1,200	$1,500	$2,000	$1,600	$400	$1,500
Salt Lake	$1,300	$3,100	$3,300	$2,600	$2,500	$1,800	$4,100	$2,300	$1,500	$1,900	$2,500	$2,100	$530	$2,000
San Joaquin	$2,900	$7,000	$7,400	$5,800	$5,600	$4,000	$9,100	$5,200	$3,400	$4,300	$5,600	$4,600	$1,300	$4,400
Seattle	$280	$680	$720	$530	$550	$390	$890	$500	$330	$420	$550	$450	$110	$330
National average	**$1,200**	**$3,000**	**$3,200**	**$2,400**	**$2,400**	**$1,700**	**$3,900**	**$2,200**	**$1,400**	**$1,800**	**$2,400**	**$1,900**	**$490**	**$1,800**

* These estimates assume a 50 percent reduction in VOC emissions, an analysis year of 2015, and a 3 percent discount rate. All estimates are rounded to two significant digits. These estimates have been updated from Fann, Fulcher, and Hubbell (2009) to reflect a more recent currency year and EPA's current VSL estimate. Using a discount rate of 7 percent, the benefit-per-ton estimates would be approximately 9 percent lower. Assuming a 75 percent reduction in VOC emissions would increase the benefit-per-ton estimates by approximately 4 percent to 52 percent. Assuming a 25 percent reduction in VOC emissions would decrease the benefit-per-ton estimates by 5 percent to 52 percent. EPA generally presents a range of benefits estimates derived from Pope et al. (2002) to Laden et al. (2006) and provides the benefits estimates derived from the expert functions from Roman et al. (2008) as a characterization of uncertainty.

4.5.3 Organic PM welfare effects

According to the residual risk assessment for this sector (U.S. EPA, 2011a), persistent and bioaccumulative HAP reported as emissions from oil and gas operations include polycyclic organic matter (POM). POM defines a broad class of compounds that includes the polycyclic aromatic hydrocarbon compounds (PAHs). Several significant ecological effects are associated with deposition of organic particles, including persistent organic pollutants, and PAHs (U.S. EPA, 2009a).

PAHs can accumulate in sediments and bioaccumulate in freshwater, flora, and fauna. The uptake of organics depends on the plant species, site of deposition, physical and chemical properties of the organic compound and prevailing environmental conditions (U.S. EPA, 2009a). PAHs can accumulate to high enough concentrations in some coastal environments to pose an environmental health threat that includes cancer in fish populations, toxicity to organisms living in the sediment and risks to those (e.g., migratory birds) that consume these organisms. Atmospheric deposition of particles is thought to be the major source of PAHs to the sediments of coastal areas of the U.S. Deposition of PM to surfaces in urban settings increases the metal and organic component of storm water runoff. This atmospherically-associated pollutant burden can then be toxic to aquatic biota. The contribution of atmospherically deposited PAHs to aquatic food webs was demonstrated in high elevation mountain lakes with no other anthropogenic contaminant sources.

The recently completed Western Airborne Contaminants Assessment Project (WACAP) is the most comprehensive database on contaminant transport and PM depositional effects on sensitive ecosystems in the Western U.S. (Landers et al., 2008). In this project, the transport, fate, and ecological impacts of anthropogenic contaminants from atmospheric sources were assessed from 2002 to 2007 in seven ecosystem components (air, snow, water, sediment, lichen, conifer needles, and fish) in eight core national parks. The study concluded that bioaccumulation of semi-volatile organic compounds occurred throughout park ecosystems, an elevational gradient in PM deposition exists with greater accumulation in higher altitude areas, and contaminants accumulate in proximity to individual agriculture and industry sources, which is

counter to the original working hypothesis that most of the contaminants would originate from Eastern Europe and Asia.

4.5.4 Visibility Effects

Reducing secondary formation of $PM_{2.5}$ would improve visibility throughout the U.S. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Suspended particles and gases degrade visibility by scattering and absorbing light. Higher visibility impairment levels in the East are due to generally higher concentrations of fine particles, particularly sulfates, and higher average relative humidity levels. Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Previous analyses (U.S. EPA, 2006b; U.S. EPA, 2010c; U.S. EPA, 2011a) show that visibility benefits are a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility related benefits, nor are we able to determine whether VOC emission reductions would be likely to have a significant impact on visibility in urban areas or Class I areas.

4.6 VOCs as an Ozone Precursor

This rulemaking would reduce emissions of VOCs, which are also precursors to secondary formation of ozone. Ozone is not emitted directly into the air, but is created when its two primary components, volatile organic compounds (VOC) and oxides of nitrogen (NOx), combine in the presence of sunlight. In urban areas, compounds representing all classes of VOCs and CO are important compounds for ozone formation, but biogenic VOCs emitted from vegetation tend to be more important compounds in non-urban vegetated areas (U.S. EPA, 2006a). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. However, we have not quantified the ozone-related benefits in this analysis for several reasons. First, previous rules have shown that the monetized benefits associated with reducing ozone exposure are generally smaller than PM-related benefits, even when ozone is the pollutant targeted for control (U.S. EPA, 2010a). Second, the complex non-linear chemistry of ozone formation introduces uncertainty to the development and application of a benefit-per-ton estimate. Third, the impact of reducing VOC

emissions is spatially heterogeneous depending on local air chemistry. Urban areas with a high population concentration are often VOC-limited, which means that ozone is most effectively reduced by lowering VOCs. Rural areas and downwind suburban areas are often NOx-limited, which means that ozone concentrations are most effectively reduced by lowering NOx emissions, rather than lowering emissions of VOCs. Between these areas, ozone is relatively insensitive to marginal changes in both NOx and VOC.

Due to time limitations under the court-ordered schedule, we were unable to perform air quality modeling for this rule. Due to the high degree of variability in the responsiveness of ozone formation to VOC emission reductions, we are unable to estimate the effect that reducing VOCs will have on ambient ozone concentrations without air quality modeling.

4.6.1 Ozone health effects and valuation

Reducing ambient ozone concentrations is associated with significant human health benefits, including mortality and respiratory morbidity (U.S. EPA, 2010a). Epidemiological researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2006c). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to ozone (e.g., U.S. EPA, 2010a; U.S. EPA, 2011a). These health effects include respiratory morbidity such as asthma attacks, hospital and emergency department visits, school loss days, as well as premature mortality. Although EPA has not quantified these effects in benefits analyses previously, the scientific literature is suggestive that exposure to ozone is also associated with chronic respiratory damage and premature aging of the lungs.

In a recent EPA analysis, EPA estimated that reducing 15,000 tons of VOCs from industrial boilers resulted in $3.6 to $15 million of monetized benefits from reduced ozone exposure (U.S. EPA, 2011b).[47] This implies a benefit-per-ton for ozone reductions of $240 to $1,000 per ton of VOCs reduced. While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in the boiler analysis. Therefore, we do not believe that those

[47] While EPA has estimated the ozone benefits for many scenarios, most of these scenarios also reduce NOx emissions, which make it difficult to isolate the benefits attributable to VOC reductions.

estimates to provide useful estimates of the monetized benefits of these rules, even as a bounding exercise.

4.6.2 Ozone vegetation effects

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2006a). Sensitivity to ozone is highly variable across species, with over 65 plan species identified as "ozone-sensitive", many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects are considered adverse to the public welfare and can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced crop yields, visible foliar injury, reduced plant vigor (e.g., increased susceptibility to harsh weather, disease, insect pest infestation, and competition), species composition shift, and changes in ecosystems and associated ecosystem services.

4.6.3 Ozone climate effects

Ozone is a well-known short-lived climate forcing (SLCF) greenhouse gas (GHG) (U.S. EPA, 2006a). Stratospheric ozone (the upper ozone layer) is beneficial because it protects life on Earth from the sun's harmful ultraviolet (UV) radiation. In contrast, tropospheric ozone (ozone in the lower atmosphere) is a harmful air pollutant that adversely affects human health and the environment and contributes significantly to regional and global climate change. Due to its short atmospheric lifetime, tropospheric ozone concentrations exhibit large spatial and temporal variability (U.S. EPA, 2009b). A recent United Nations Environment Programme (UNEP) study reports that the threefold increase in ground level ozone during the past 100 years makes it the third most important contributor to human contributed climate change behind CO_2 and methane. This discernable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles. This study provides the most comprehensive analysis to date of the benefits of measures to reduce SLCF gases including methane, ozone, and black carbon assessing the health, climate, and agricultural benefits of a suite of mitigation technologies. The report concludes that the climate is changing now, and these changes have the potential to "trigger abrupt transitions such as the release of carbon from thawing permafrost and biodiversity loss" (UNEP 2011). While reducing long-lived GHGs such as CO_2 is necessary to

protect against long-term climate change, reducing SLCF gases including ozone is beneficial and will slow the rate of climate change within the first half of this century (UNEP 2011).

4.7 Methane (CH_4)

4.7.1 Methane as an ozone precursor

This rulemaking would reduce emissions of methane, a long-lived GHG and also a precursor to ozone. In remote areas, methane is a dominant precursor to tropospheric ozone formation (U.S. EPA, 2006a). Unlike NOx and VOCs, which affect ozone concentrations regionally and at hourly time scales, methane emission reductions require several decades for the ozone response to be fully realized, given methane's relatively long atmospheric lifetime (HTAP, 2010). Studies have shown that reducing methane can reduce global background ozone concentrations over several decades, which would benefit both urban and rural areas (West et al., 2006). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. The health, welfare, and climate effects associated with ozone are described in the preceding sections. Without air quality modeling, we are unable to estimate the effect that reducing methane will have on ozone concentrations at particular locations.

4.7.2 Methane climate effects and valuation

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that once emitted into the atmosphere absorbs terrestrial infrared radiation which contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone also impacts global temperatures. According to the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (2007), in 2004 the cumulative changes in methane concentrations since preindustrial times contributed about 14 percent to global warming due to anthropogenic GHG sources, making methane the second leading long-lived climate forcer after CO_2 globally. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.

Processes in the oil and gas category emit significant amounts of methane. The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009 (published April 2011) estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 251.55 ($MMtCO_2$-e). In 2009, total methane emissions from the oil and gas industry represented nearly 40 percent of the total methane emissions from all sources and account for about 5 percent of all CO_2-equivalent (CO_2-e) emissions in the U.S., with natural gas systems being the single largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2011b, Table ES-2). It is important to note that the 2009 emissions estimates from well completions and recompletions exclude a significant number of wells completed in tight sand plays and the Marcellus Shale, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays and the Marcellus Shale, and such an adjustment is also being considered as a planned improvement in next year's Inventory. This adjustment would increase the 2009 Inventory estimate by about 80 $MMtCO_2$-e. The total methane emissions from Petroleum and Natural Gas Systems based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus Shale, is approximately 330 $MMtCO_2$-e.

This rulemaking proposes emission control technologies and regulatory alternatives that will significantly decrease methane emissions from the oil and natural gas sector in the United States. The regulatory alternative proposed for this rule is expected to reduce methane emissions annually by about 3.4 million short tons or approximately 65 million metric tons CO_2-e. These reductions represent about 26 percent of the GHG emissions for this sector reported in the 1990-2009 U.S. GHG Inventory (251.55 $MMTCO_2$-e). This annual CO_2-e reduction becomes about 62 million metric tons when the secondary impacts associated with increased combustion and supplemental energy use on the producer side and CO_2-e emissions from changes in consumption patterns previously discussed are considered. However, it is important to note the emissions reductions are based upon predicted activities in 2015; EPA did not forecast sector-level emissions to 2015 for this rulemaking. The climate co-benefit from these reductions are

equivalent of taking approximately 11 million typical passenger cars off the road or eliminating electricity use from about 7 million typical homes each year.[48]

EPA estimates the social benefits of regulatory actions that have a small or "marginal" impact on cumulative global CO_2 emissions using the "social cost of carbon" (SCC). The SCC is an estimate of the net present value of the flow of monetized damages from a one metric ton increase in CO_2 emissions in a given year (or from the alternative perspective, the benefit to society of reducing CO_2 emissions by one ton). The SCC includes (but is not limited to) climate damages due to changes in net agricultural productivity, human health, property damages from flood risk, and ecosystem services due to climate change. The SCC estimates currently used by the Agency were developed through an interagency process that included EPA and other executive branch entities, and concluded in February 2010. The Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 for the final joint EPA/Department of Transportation Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards provides a complete discussion of the methods used to develop the SCC estimates (Interagency Working Group on Social Cost of Carbon, 2010).

To estimate global social benefits of reduced CO_2 emissions, the interagency group selected four SCC values for use in regulatory analyses: $6, $25, $40, and $76 per metric ton of CO_2 emissions in 2015, in 2008 dollars. The first three values are based on the average SCC estimated using three integrated assessment models (IAMs), at discount rates of 5.0, 3.0, and 2.5 percent, respectively. When valuing the impacts of climate change, IAMs couple economic and climate systems into a single model to capture important interactions between the components. SCCs estimated using different discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context. The fourth value is the 95th percentile of the distribution of SCC estimates from all three models at a 3.0 percent discount rate. It is included to represent higher-than-expected damages from temperature change further out in the tails of the SCC distribution.

[48] US Environmental Protection Agency. Greenhouse Gas Equivalency Calculator available at: http://www.epa.gov/cleanenergy/energy-resources/calculator.html accessed 07/19/11.

Although there are relatively few region- or country-specific estimates of SCC in the literature, the results from one model suggest the ratio of domestic to global benefits of emission reductions varies with key parameter assumptions. For example, with a 2.5 or 3 percent discount rate, the U.S. benefit is about 7-10 percent of the global benefit, on average, across the scenarios analyzed. Alternatively, if the fraction of GDP lost due to climate change is assumed to be similar across countries, the domestic benefit would be proportional to the U.S. share of global GDP, which is currently about 23 percent. On the basis of this evidence, values from 7 to 23 percent should be used to adjust the global SCC to calculate domestic effects. It is recognized that these values are approximate, provisional, and highly speculative. There is no a priori reason why domestic benefits should be a constant fraction of net global damages over time. (Interagency Working Group on Social Cost of Carbon, 2010).

The interagency group noted a number of limitations to the SCC analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. The limited amount of research linking climate impacts to economic damages makes estimating damages from climate change even more difficult. The interagency group hopes that over time researchers and modelers will work to fill these gaps and that the SCC estimates used for regulatory analysis by the Federal government will continue to evolve with improvements in modeling. Additional details on these limitations are discussed in the SCC TSD.

A significant limitation of the aforementioned interagency process particularly relevant to this rulemaking is that the social costs of non-CO_2 GHG emissions were not estimated. Specifically, the interagency group did not directly estimate the social cost of non-CO_2 GHGs using the three models. Moreover, the group determined that it would not transform the CO_2 estimates into estimates for non-CO_2 GHGs using global warming potentials (GWPs), which measure the ability of different gases to trap heat in the atmosphere (i.e., radiative forcing per unit of mass) over a particular timeframe relative to CO_2. One potential method for approximating the value of marginal non-CO_2 GHG emission reductions is to convert the reductions to CO_2-equivalents which may then be valued using the SCC. Conversion to CO_2-e is

typically done using the GWPs for the non-CO_2 gas. The GWP is an aggregate measure that approximates the additional energy trapped in the atmosphere over a given timeframe from a perturbation of a non-CO_2 gas relative to CO_2. The time horizon most commonly used is 100 years. One potential problem with utilizing temporally aggregated statistics, such as the GWPs, is that the additional radiative forcing from the GHG perturbation is not constant over time and any differences in temporal dynamics between gases will be lost. This is a potentially confounding issue given that the social cost of GHGs is based on a discounted stream of damages that are non-linear in temperature. For example, methane has an expected adjusted atmospheric lifetime of about 12 years and associated GWP of 21 (IPCC Second Assessment Report (SAR) 100-year GWP estimate). Gases with a shorter lifetime, such as methane, have impacts that occur primarily in the near term and thus are not discounted as heavily as those caused by the longer-lived gases, while the GWP treats additional forcing the same independent of when it occurs in time. Furthermore, the baseline temperature change is lower in the near term and therefore the additional warming from relatively short lived gases will have a lower marginal impact relative to longer lived gases that have an impact further out in the future when baseline warming is higher. The GWP also relies on an arbitrary time horizon and constant concentration scenario. Both of which are inconsistent with the assumptions used by the SCC interagency workgroup. Finally, impacts other than temperature change also vary across gases in ways that are not captured by GWP. For instance, CO_2 emissions, unlike methane will result in CO_2 passive fertilization to plants.

In light of these limitations, and the significant contributions of non-CO_2 emissions to climate change, further analysis is required to link non-CO_2 emissions to economic impacts and to develop social cost estimates for methane specifically. Such work would feed into efforts to develop a monetized value of reductions in methane greenhouse gas emissions in assessing the co-benefits of this rulemaking. As part of ongoing work to further improve the SCC estimates, the interagency group hopes to develop methods to value greenhouse gases other than CO_2, such as methane, by the time SCC estimates for CO_2 emissions are revised.

The EPA recognizes that the methane reductions proposed in this rule will provide significant economic climate co-benefits to society. However, EPA finds itself in the position of

having no interagency accepted monetary values to place on these co-benefits. The 'GWP approach' of converting methane to CO_2-e using the GWP of methane, as previously described, is one approximation method for estimating the monetized value of the methane reductions anticipated from this rule. This calculation uses the GWP of the non-CO_2 gas to estimate CO_2 equivalents and then multiplies these CO_2 equivalent emission reductions by the SCC to generate monetized estimates of the co-benefits. If one makes these calculations for the proposed Option 2 (including expected methane emission reductions from the NESHAP amendments and NSPS and considers secondary impacts) of the oil and gas rule, the 2015 co-benefits vary by discount rate and range from about $373 million to over $4.7 billion; the SCC at the 3 percent discount rate ($25 per metric ton) results in an estimate of $1.6 billion in 2015. These co-benefits equate to a range of approximately $110 to $1,400 per short ton of methane reduced depending upon the discount rate assumed with a per ton estimate of $480 at the 3 percent discount rate

As previously stated, these co-benefit estimates are not the same as would be derived using a directly computed social cost of methane (using the integrated assessment models employed to develop the SCC estimates) for a variety of reasons including the shorter atmospheric lifetime of methane relative to CO_2 (about 12 years compared to CO_2 whose concentrations in the atmosphere decay on timescales of decades to millennia). The climate impacts also differ between the pollutants for reasons other than the radiative forcing profiles and atmospheric lifetimes of these gases. Methane is a precursor to ozone and ozone is a short-lived climate forcer as previously discussed. This use of the SAR GWP to approximate benefits may underestimate the direct radiative forcing benefits of reduced ozone levels, and does not capture any secondary climate co-benefits involved with ozone-ecosystem interactions. In addition, a recent NCEE working paper suggests that this quick 'GWP approach' to benefits estimation will likely understate the climate benefits of methane reductions in most cases (Marten and Newbold, 2011). This conclusion is reached using the 100 year GWP for methane of 25 as put forth in the IPCC Fourth Assessment Report as opposed to the lower value of 21 used in this analysis. Using the higher GWP estimate of 25 would increase these reported methane climate co-benefit estimates by about 19 percent. Although the IPCC Fourth Assessment Report suggested a GWP of 25, EPA has used GWP of 21 consistent with the IPCC SAR to estimate the methane climate co-benefits for this oil and gas proposal. The use of the SAR GWP values allows comparability

of data collected in this proposed rule to the national GHG inventory that EPA compiles annually to meet U.S. commitments to the United Nations Framework Convention on Climate Change (UNFCCC). To comply with international reporting standards under the UNFCCC, official emission estimates are to be reported by the U.S. and other countries using SAR GWP values. The UNFCCC reporting guidelines for national inventories were updated in 2002 but continue to require the use of GWPs from the SAR. The parties to the UNFCCC have also agreed to use GWPs based upon a 100-year time horizon although other time horizon values are available. The SAR GWP value for methane is also currently used to establish GHG reporting requirements as mandated by the GHG Reporting Rule (2010e) and is used by the EPA to determine Title V and Prevention of Significant Deterioration GHG permitting requirements as modified by the GHG Tailoring Rule (2010f).

EPA also undertook a literature search for estimates of the marginal social cost of methane. A range of marginal social cost of methane benefit estimates are available in published literature (Fankhauser (1994), Kandlikar (1995), Hammitt et al. (1996), Tol et al. (2003), Tol, et al. (2006), Hope (2005) and Hope and Newberry (2006). Most of these estimates are based upon modeling assumptions that are dated and inconsistent with the current SCC estimates. Some of these studies focused on marginal methane reductions in the 1990s and early 2000s and report estimates for only the single year of interest specific to the study. The assumptions underlying the social cost of methane estimates available in the literature differ from those agreed upon by the SCC interagency group and in many cases use older versions of the IAMs. Without additional analysis, the methane climate benefit estimates available in the current literature are not acceptable to use to value the methane reductions proposed in this rulemaking.

Due to the uncertainties involved with 'GWP approach' estimates presented and estimates available in the literature, EPA chooses not to compare these co-benefit estimates to the costs of the rule for this proposal. Rather, the EPA presents the 'GWP approach' climate co-benefit estimates as an interim method to produce lower-bound estimates until the interagency group develops values for non-CO_2 GHGs. EPA requests comments from interested parties and the public about this interim approach specifically and more broadly about appropriate methods to monetize the climate co-benefits of methane reductions. In particular, EPA seeks public comments to this proposed rulemaking regarding social cost of methane estimates that may be

used to value the co-benefits of methane emission reductions anticipated for the oil and gas industry from this rule. Comments specific to whether GWP is an acceptable method for generating a placeholder value for the social cost of methane until interagency modeled estimates become available are welcome. Public comments may be provided in the official docket for this proposed rulemaking in accordance with the process outlined in the preamble for the rule. These comments will be considered in developing the final rule for this rulemaking.

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5 STATUTORY AND EXECUTIVE ORDER REVIEWS

5.1 Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, the EPA submitted this action to OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, the EPA prepared a RIA of the potential costs and benefits associated with this action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 5-1 shows the results of the cost and benefits analysis for these proposed rules.

Table 5-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NSPS and NESHAP Amendments in 2015 (millions of 2008$)[1]

	Proposed NSPS	Proposed NESHAP Amendments	Proposed NSPS and NESHAP Amendments Combined
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$45 million	$16 million	-$29 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	37,000 tons of HAPs	1,400 tons of HAPs	38,000 tons of HAPs
	540,000 tons of VOCs	9,200 tons of VOCs	540,000 tons of VOCs
	3.4 million tons of methane	4,900 tons of methane	3.4 million tons of methane
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

5.2 Paperwork Reduction Act

The information collection requirements in this proposed action have been submitted for approval to OMB under the PRA, 44 U.S.C. 3501, et seq. The ICR document prepared by the EPA has been assigned EPA ICR Numbers 1716.07 (40 CFR part 60, subpart OOOO), 1788.10 (40 CFR part 63, subpart HH), 1789.07 (40 CFR part 63, subpart HHH), and 1086.10 (40 CFR part 60, subparts KKK and subpart LLL).

The information to be collected for the proposed NSPS and the proposed NESHAP amendments are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

These proposed rules would require maintenance inspections of the control devices, but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

For sources subject to the proposed NSPS, the burden represents labor hours and costs associated from annual reporting and recordkeeping for each affected facility. The estimated burden is based on the annual expected number of affected operators for the first three years following the effective date of the standards. The burden is estimated to be 560,000 labor hours at a cost of around$18 million per year. This includes the labor and cost estimates previously estimated for sources subject to 40 CFR part 60, subpart KKK and subpart LLL (which is being incorporated into 40 CFR part 60, subpart OOOO). The average hours and cost per regulated entity, which is assumed to be on a per operator basis except for natural gas processing plants (which are estimated on a per facility basis) subject to the NSPS for oil and natural gas production and natural gas transmissions and distribution facilities would be 110 hours per response and $3,693 per response based on an average of 1,459 operators responding per year

and 16 responses per year. The majority of responses are expected to be notifications of construction. One annual report is required that may include all affected facilities owned per each operator. Burden by for the proposed NSPS was based on EPA ICR Number 1716.07.

The estimated recordkeeping and reporting burden after the effective date of the proposed amendments is estimated for all affected major and area sources subject to the oil and natural gas production NESHAP (40 CFR 63, subpart HH) to be approximately 63,000 labor hours per year at a cost of $2.1 million per year. For the natural gas transmission and storage NESHAP, the recordkeeping and reporting burden is estimated to be 2,500 labor hours per year at a cost of $86,800 per year. This estimate includes the cost of reporting, including reading instructions, and information gathering. Recordkeeping cost estimates include reading instructions, planning activities, and conducting compliance monitoring. The average hours and cost per regulated entity subject to the oil and natural gas production NESHAP would be 72 hours per year and $2,500 per year based on an average of 846 facilities per year and three responses per facility. For the natural gas transmission and storage NESHAP, the average hours and cost per regulated entity would be 50 hours per year and $1,600 per year based on an average of 53 facilities per year and three responses per facility. Burden is defined at 5 CFR 1320.3(b). Burden for the oil and natural gas production NESHAP is estimated under EPA ICR Number 1788.10. Burden for the natural gas transmission and storage NESHAP is estimated under EPA ICR Number 1789.07.

5.3 Regulatory Flexibility Act

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises. For purposes of assessing the impact of this rule on small entities, a small entity is defined as: (1) a small business whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a

population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

5.3.1 Proposed NSPS

After considering the economic impact of the Proposed NSPS on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities (SISNOSE). EPA performed a screening analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. Based upon the analysis in Section 7.4 in this RIA, EPA recognizes that a subset of small firms is likely to be significantly impacted by the proposed NSPS. However, the number of significantly impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that the firm-level compliance cost estimates used in the small business impacts analysis are likely over-estimates of the compliance costs faced by firms under the Proposed NSPS; these estimates do not include the revenues that producers are expected receive from the additional natural gas recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from well completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated, if not fully offset. Although this final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities by the selection of highly cost-effective controls and specifying monitoring requirements that are the minimum to insure compliance.

5.3.2 Proposed NESHAP Amendments

After considering the economic impact of the Proposed NESHAP Amendments on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. Based upon the analysis in Section 7.4 in this RIA, we estimate that 62 of the 118 firms (53 percent) that own potentially affected facilities are small entities. EPA performed a screening analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to

revenues. Meanwhile 10 firms (16 percent) are likely to have impacts greater than 1 percent. Four of these 10 firms are likely to have impacts greater than 3 percent. While these 10 firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211. Although this final rule will not impact a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities by setting the final emissions limits at the MACT floor, the least stringent level allowed by law.

5.4 Unfunded Mandates Reform Act

This proposed rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any one year. Thus, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments because it contains no requirements that apply to such governments nor does it impose obligations upon them.

5.5 Executive Order 13132: Federalism

This proposed rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this proposed rule.

5.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance

costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement. The EPA has concluded that this proposed rule will not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effect on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

5.7 Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This proposed rule is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is economically significant as defined in Executive Order 12866. However, EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action would not relax the control measures on existing regulated sources. EPA's risk assessments (included in the docket for this proposed rule) demonstrate that the existing regulations are associated with an acceptable level of risk and provide an ample margin of safety to protect public health.

5.8 Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211, (66 FR 28,355, May 22, 2001), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of Executive Order 13211 defines "significant energy actions" as "any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: 1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant

adverse effect on the supply, distribution, or use of energy; or 2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action."

The proposed rules will result in the addition of control equipment and monitoring systems for existing and new sources within the oil and natural gas industry. The proposed NESHAP amendments are unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the proposed NESHAP amendments are not "significant energy actions" as defined in Executive Order 13211, (66 FR 28355, May 22, 2001).

The proposed NSPS is also unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the proposed NSPS is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001). The basis for the determination is as follows.

We use the NEMS to estimate the impacts of the proposed NSPS on the United States energy system. The NEMS is a publically available model of the United States energy economy developed and maintained by the Energy Information Administration of the U.S. DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

Proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One pollution control requirement of the proposed NSPS also captures saleable condensates. The revenues from additional natural gas and condensate recovery are expected to offset the costs of implementing the proposed NSPS.

The analysis of energy impacts for the proposed NSPS that includes the additional product recovery shows that domestic natural gas production is estimated to increase (20 billion cubic feet or 0.1 percent) and natural gas prices to decrease ($0.04/Mcf or 0.9 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. Domestic crude oil production is not estimated to change, while crude oil prices are estimated to decrease slightly ($0.02/barrel or less than 0.1 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. All prices are in 2008 dollars.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden.

5.9 National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law No. 104-113 (15 U.S.C. 272 note) directs the EPA to use VCS in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

The proposed rule involves technical standards. Therefore, the requirements of the NTTAA apply to this action. We are proposing to revise 40 CFR part 63, subparts HH and HHH to allow ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses (Part 10, Instruments and Apparatus) to be used in lieu of EPA Methods 3B, 6 and 16A. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990. Also, we are proposing to revise 40 CFR part 63, subpart HHH, to allow ASTM D6420-99(2004), "Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry" to be used in lieu of EPA Method 18. For a detailed discussion of this VCS, and its appropriateness as a substitute for Method 18, see the final oil and natural gas production NESHAP (Area Sources) (72 FR 36, January 3, 2007).

As a result, the EPA is proposing ASTM D6420-99 for use in 40 CFR part 63, subpart HHH. The EPA also proposes to allow Method 18 as an option in addition to ASTM D6420-99(2004). This would allow the continued use of GC configurations other than GC/MS.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this regulation.

5.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on Environmental Justice (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

To examine the potential for any EJ issues that might be associated with each source category, we evaluated the distributions of HAP-related cancer and noncancer risks across different social, demographic, and economic groups within the populations living near the facilities where these source categories are located. The methods used to conduct demographic analyses for this rule are described in section VII.D of the preamble for this rule. The development of demographic analyses to inform the consideration of EJ issues in EPA rulemakings is an evolving science. The EPA offers the demographic analyses in this proposed rulemaking as examples of how such analyses might be developed to inform such consideration, and invites public comment on the approaches used and the interpretations made from the results, with the hope that this will support the refinement and improve utility of such analyses for future rulemakings.

For the demographic analyses, we focused on the populations within 50 km of any facility estimated to have exposures to HAP which result in cancer risks of 1-in-1 million or greater, or noncancer HI of 1 or greater (based on the emissions of the source category or the facility, respectively). We examined the distributions of those risks across various demographic groups, comparing the percentages of particular demographic groups to the total number of people in those demographic groups nationwide. The results, including other risk metrics, such as average risks for the exposed populations, are documented in source category-specific technical reports in the docket for both source categories covered in this proposal.

As described in the preamble, our risk assessments demonstrate that the regulations for the oil and natural gas production and natural gas transmission and storage source categories, are

associated with an acceptable level of risk and that the proposed additional requirements will provide an ample margin of safety to protect public health.

Our analyses also show that, for these source categories, there is no potential for an adverse environmental effect or human health multi-pathway effects, and that acute and chronic noncancer health impacts are unlikely. The EPA has determined that although there may be an existing disparity in HAP risks from these sources between some demographic groups, no demographic group is exposed to an unacceptable level of risk.

6 COMPARISON OF BENEFITS AND COSTS

Because we are unable to estimate the monetary value of the emissions reductions from the proposed rule, we have chosen to rely upon a break-even analysis to estimate what the monetary value benefits would need to attain in order to equal the costs estimated to be imposed by the rule. A break-even analysis answers the question, "What would the benefits need to be for the benefits to exceed the costs." While a break-even approach is not equivalent to a benefits analysis or even a net benefits analysis, we feel the results are illustrative, particularly in the context of previously modeled benefits.

The total cost of the proposed NSPS in the analysis year of 2015 when the additional natural gas and condensate recovery is included in the analysis is estimated at -$45 million for domestic producers and consumers. EPA anticipates that this rule would prevent 540,000 tons of VOC, 3.4 million tons of methane, and 37,000 tons of HAPs in 2015 from new sources. In 2015, EPA estimates the costs for the NESHAP amendments floor option to be $16 million.[49] EPA anticipates that this rule would reduce 9,200 tons of VOC, 4,900 tons of methane, and 1,400 tons of HAPs in 2015 from existing sources. For the NESHAP amendments, a break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health benefits, and ecosystem and climate co-benefits from the reductions in VOC and methane emissions are assumed to be zero. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

For the proposed NSPS, the revenue from additional natural gas recovery already exceeds the costs, which renders a break-even analysis unnecessary. However, as discussed in Section 3.2.2., estimates of the annualized engineering costs that include revenues from natural gas product recovery depend heavily upon assumptions about the price of natural gas and hydrocarbon condensates in analysis year 2015. Therefore, we have also conducted a break-even analysis for the price of natural gas. For the NSPS, a break-even analysis suggests that the price

[49] See Section 3 of this RIA for more information regarding the cost estimates for the NESHAP.

of natural gas would need to be at least $3.77 per Mcf in 2015 for the revenue from product recovery to exceed the annualized costs. EIA forecasts that the price of natural gas would be $4.26 per Mcf in 2015. In addition to the revenue from product recovery, the NSPS would avert emissions of VOCs, HAPs, and methane, which all have value that could be incorporated into the break-even analysis. Figure 6-1 illustrates one method of analyzing the break-even point with alternate natural gas prices and VOC benefits. If, as an illustrative example, the price of natural gas was only $3.00 per Mcf, VOCs would need to be valued at $260 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

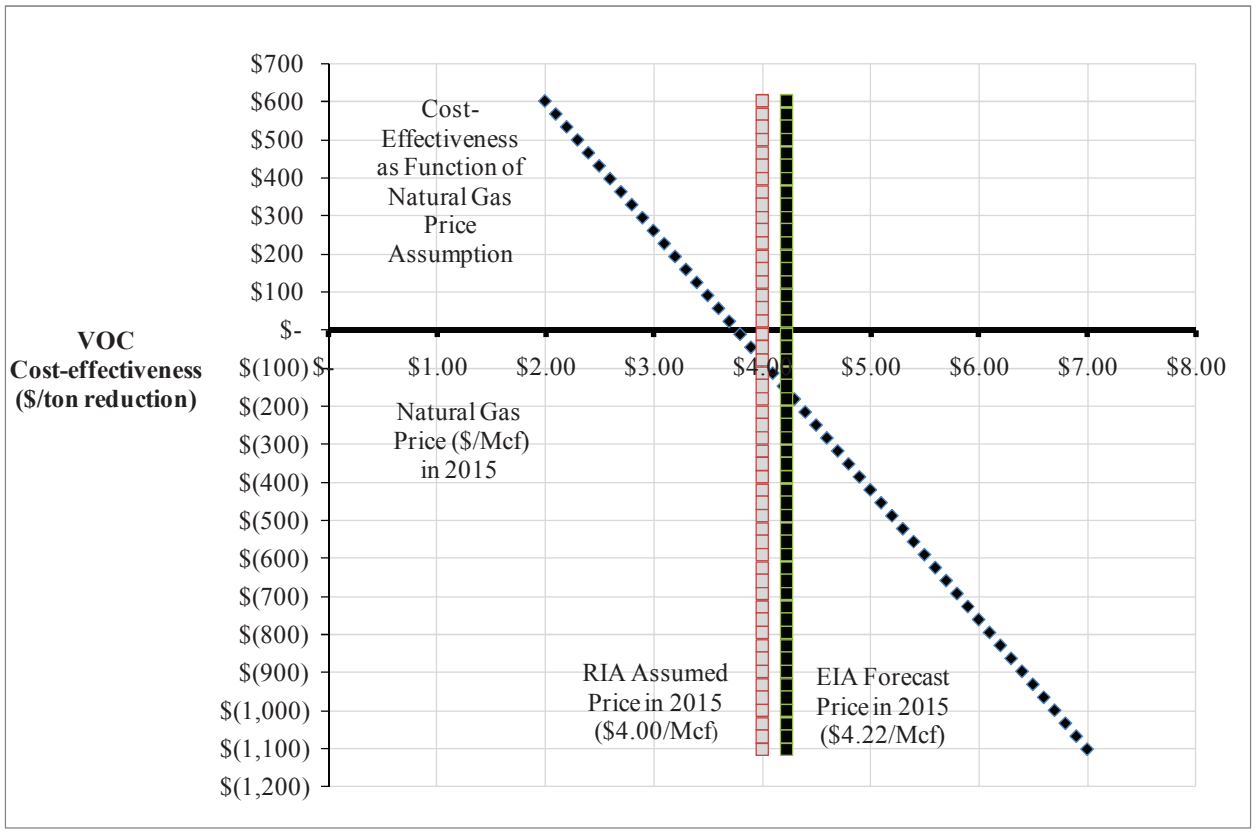


Figure 6-1 Illustrative Break-Even Diagram for Alternate Natural Gas Prices for the NSPS

With the data available, we are not able to provide a credible benefit-per-ton estimate for any of the pollutant reductions for these rules to compare to the break-even estimates. Based on the methodology from Fann, Fulcher, and Hubbell (2009), average $PM_{2.5}$ health-related benefits

of VOC emissions are valued at $280 to $7,000 per ton across a range of eight urban areas.[50] In addition, ozone benefits have been previously valued at $240 to $1,000 per ton of VOC reduced. Using the GWP approach, the climate co-benefits range from approximately $110 to $1,400 per short ton of methane reduced depending upon the discount rate assumed with a per ton estimate of $760 at the 3 percent discount rate.

These break-even benefit-per-ton estimates assume that all other pollutants have zero value. Of course, it is inappropriate to assume that the value of reducing any of these pollutants is zero. Thus, the real break-even estimate is actually lower than the estimates provided above because the other pollutants each have non-zero benefits that should be considered. Furthermore, a single pollutant can have multiple effects (e.g., VOCs contribute to both ozone and $PM_{2.5}$ formation that each have health and welfare effects) that would need to be summed in order to develop a comprehensive estimate of the monetized benefits associated with reducing that pollutant.

As previously described, the revenue from additional natural gas recovery already exceeds the costs of the NSPS, but even if the price of natural gas was only $3.00 per Mcf, it is likely that the VOC benefits would exceed the costs, As a result, even if VOC emissions from oil and natural gas operations result in monetized benefits that are substantially below the average modeled benefits, there is a reasonable chance that the benefits of these rules would exceed the costs, especially if we were able to monetize all of the benefits associated with ozone formation, visibility, HAPs, and methane.

Table 6-1 and Table 6-2 present the summary of the benefits, costs, and net benefits for the NSPS and NESHAP amendment options, respectively. Table 6-3 provides a summary of the direct and secondary emissions changes for each option.

[50] See Section 4.5 of this RIA for more information regarding $PM_{2.5}$ benefits and Section 4.6 for more information regarding ozone benefits.

Table 6-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NSPS in 2015 (millions of 2008$)[1]

	Option 1: Alternative	Option 2: Proposed[4]	Option 3: Alternative
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$19 million	-$45 million	$77 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	17,000 tons of HAPs[5]	37,000 tons of HAPs[5]	37,000 tons of HAPs[5]
	270,000 tons of VOCs	540,000 tons of VOCs	550,000 tons of VOCs
	1.6 million tons of methane	3.4 million tons of methane	3.4 million tons of methane
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

Table 6-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NESHAP amendments in 2015 (millions of 2008$)[1]

	Option 1: Proposed (Floor)
Total Monetized Benefits[2]	N/A
Total Costs[3]	$16 million
Net Benefits	N/A
Non-monetized Benefits	1,400 tons of HAPs
	9,200 tons of VOCs[4]
	4,900 tons of methane[4]
	Health effects of HAP exposure
	Health effects of $PM_{2.5}$ and ozone exposure[4]
	Visibility impairment[4]
	Vegetation effects[4]
	Climate effects[4]

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and PM as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NESHAP are anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.

[3] The cost estimates are assumed to be equivalent to the engineering cost estimates. The engineering compliance costs are annualized using a 7 percent discount rate.

[4] Reduced exposure to VOC emissions, $PM_{2.5}$ and ozone exposure, visibility and vegetation effects, and climate effects are co-benefits.

Table 6-3 Summary of Emissions Changes for the Proposed Oil and Gas NSPS and NESHAP in 2015 (short tons per year)

	Pollutant	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP
Change in Direct Emissions	VOC	-270,000	-540,000	-550,000	-9,200
	Methane	-1,600,000	-3,400,000	-3,400,000	-4,900
	HAP	-17,000	-37,000	-37,000	-1,400
Change in Secondary Emissions (Producer-Side) [1]	CO_2	990,000	990,000	990,000	5,500
	NOx	510	510	510	2.9
	PM	7.6	7.6	7.6	0.1
	CO	2,800	2,800	2,800	16
	THC	1,000	1,000	1,000	6.0
Change in Secondary Emissions (Consumer-Side)	CO_2-e	-1,000,000	1,700,000	1,400,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e	-33,000,000	-68,000,000	-70,000,000	-96,000

[1] We use the producer-side secondary impacts associated with the proposed NSPS option as a surrogate for the impacts of the other options.

7 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

7.1 Introduction

This section includes three sets of analyses for both the NSPS and NESHAP amendments:

- Energy System Impacts
- Employment Impacts
- Small Business Impacts Analysis

7.2 Energy System Impacts Analysis of Proposed NSPS

We use the National Energy Modeling System (NEMS) to estimate the impacts of the proposed NSPS on the U.S. energy system. The impacts we estimate include changes in drilling activity, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas. We evaluate whether and to what extent the increased production costs imposed by the NSPS might alter the mix of fuels consumed at a national level. With this information we estimate how the changed fuel mix affects national level CO_2-equivalent greenhouse gas emissions from energy sources. We additionally combine these estimates of changes in CO_2-equivalent greenhouse gas emissions from energy sources and emissions co-reductions of methane from the engineering analysis with NEMS analysis to estimate the net change in CO_2-equivalent greenhouse gas emissions from energy-related sources, but this analysis is reserved for the secondary environmental impacts analysis within Section 4.

A brief conceptual discussion about our energy system impacts modeling approach is necessary before going into detail on NEMS, how we implemented the regulatory impacts, and results. Economically, it is possible to view the recovered natural gas as an explicit output or as contributing to an efficiency gain at the producer level. For example, the analysis for the proposed NSPS shows that about 97 percent of the natural gas captured by emissions controls suggested by the rule is captured by performing RECs on new and existing wells that are

completed after being hydraulically fractured. The assumed $4/Mcf price for natural gas is the price paid to producers at the wellhead. In the natural gas industry, production is metered at or very near to the wellhead, and producers are paid based upon this metered production. Depending on the situation, the gas captured by RECs is sent through a temporary or permanent meter. Payments for the gas are typically made within 30 days.

To preview the energy systems modeling using NEMS, results show that after economic adjustments to the new regulations are made by producers, the captured natural gas represents both increased output (a slight increment in aggregate production) and increased efficiency (producing slightly more for less). However, because of differing objectives for the regulatory analysis we treat the associated savings differently in the engineering cost analysis (as an explicit output) and in NEMS (as an efficiency gain).

In the engineering cost analysis, it is necessary to estimate the expected costs and revenues from implementing emissions controls at the unit level. Because of this, we estimate the net costs as expected costs minus expected revenues for representative units. On the other hand, NEMS models the profit maximizing behavior of representative project developers at a drilling project level. The net costs of the regulation alter the expected discounted cash flow of drilling and implementing oil and gas projects, and the behavior of the representative drillers adjusts accordingly. While in the regulatory case natural gas drilling has become more efficient because of the gas recovery, project developers still interact with markets for which supply and demand are simultaneously adjusting. Consequently, project development adjusts to a new equilibrium. While we believe the cost savings as measured by revenues from selling recovered gas (engineering costs) and measured by cost savings from averted production through efficiency gains (energy economic modeling) are approximately the same, it is important to note that the engineering cost analysis and the national-level cost estimates do not incorporate economic feedbacks such as supply and demand adjustments.

7.2.1 Description of the Department of Energy National Energy Modeling System

NEMS is a model of U.S. energy economy developed and maintained by the Energy Information Administration of the U.S. Department of Energy. NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy

economy from the current year to 2035. DOE first developed NEMS in the 1980s, and the model has been undergone frequent updates and expansion since. DOE uses the modeling system extensively to produce issue reports, legislative analyses, and respond to Congressional inquiries.

EIA is legally required to make the NEMS system source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of the NEMS model, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues.

NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions. The dynamics of the energy system are governed by assumptions about energy and environmental policies, technological developments, resource supplies, demography, and macroeconomic conditions. An overview of the model and complete documentation of NEMS can be found at <http://www.eia.doe.gov/oiaf/aeo/overview/index.html>.

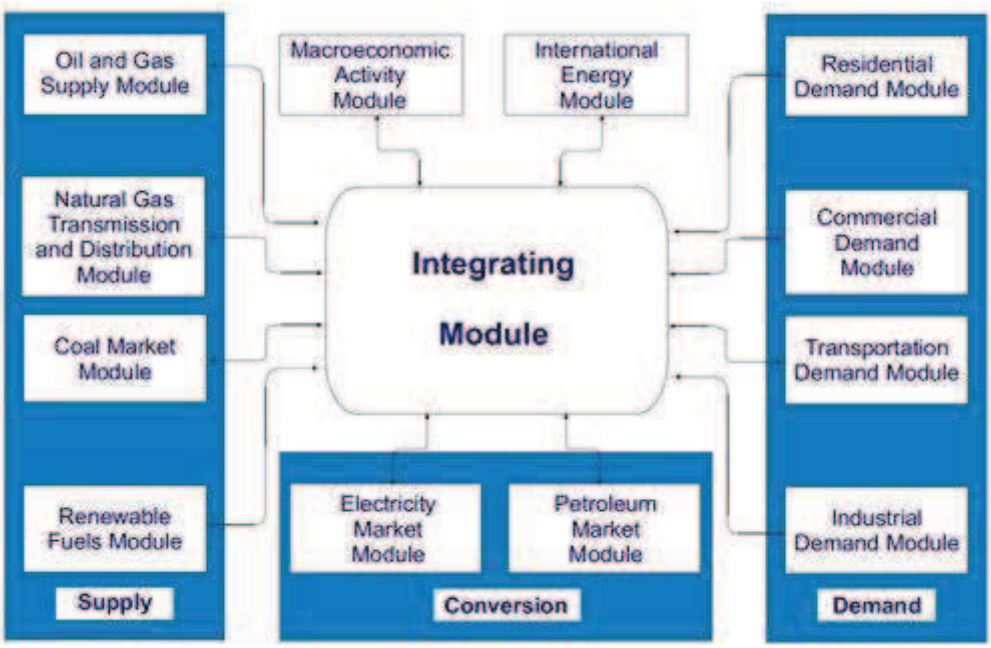


Figure 7-1 Organization of NEMS Modules (source: U.S. Energy Information Administration)

NEMS is a large-scale, deterministic mathematical programming model. NEMS iteratively solves multiple models, linear and non-linear, using nonlinear Gauss-Seidel methods (Gabriel et al. 2001). What this means is that NEMS solves a single module, holding all else constant at provisional solutions, then moves to the next model after establishing an updated provisional solution.

NEMS provides what EIA refers to as "mid-term" projections to the year 2035. However, as this RIA is concerned with estimating regulatory impacts in the first year of full implementation, our analysis focuses upon estimated impacts in the year 2015, with regulatory costs first imposed in 2011. For this RIA, we draw upon the same assumptions and model used in the Annual Energy Outlook 2011.[51] The RIA baseline is consistent with that of the Annual Energy Outlook 2011 which is used extensively in Section 2 in the Industry Profile.

[51] Assumptions for the 2011 Annual Energy Outlook can be found at <http://www.eia.gov/forecasts/aeo/assumptions/index.cfm>.

7.2.2 Inputs to National Energy Modeling System

To model potential impacts associated with the NSPS, we modified oil and gas production costs within the Oil and Gas Supply Module (OGSM) of NEMS and domestic and Canadian natural gas production within the Natural Gas Transmission and Distribution Module (NGTDM). The OGSM projects domestic oil and gas production from onshore, offshore, Alaskan wells, as well as having a smaller-scale treatment of Canadian oil and gas production (U.S. EIA, 2010). The treatment of oil and gas resources is detailed in that oil, shale oil, conventional gas, shale gas, tight sands gas, and coalbed methane (CBM) are explicitly modeled. New exploration and development is pursued in the OGSM if the expected net present value of extracted resources exceeds expected costs, including costs associated with capital, exploration, development, production, and taxes. Detailed technology and reservoir-level production economics govern finding and success rates and costs.

The structure of the OGSM is amenable to analyzing potential impacts of the Oil and Natural Gas NSPS. We are able to target additional expenditures for environmental controls expected to be required by the NSPS on new exploratory and developmental oil and gas production activities, as well as add additional costs to existing projects. We model the impacts of additional environmental costs, as well as the impacts of additional product recovery. We explicitly model the additional natural gas recovered when implementing the NSPS regulatory options. However, we are unable to explicitly model the additional production of condensates expected to be recovered by reduced emissions completions, although we incorporate expected revenues from the condensate recovery in the economic evaluation of new drilling projects.

While the oil production simulated by the OGSM is sent to the refining module (the Petroleum Market Module), simulated natural gas production is sent to a transmission and distribution network captured in the NGTDM. The NGTDM balances gas supplies and prices and "negotiates" supply and consumption to determine a regional equilibrium between supply, demand and prices, including imports and exports via pipeline or LNG. Natural gas transmitted through a simplified arc-node representation of pipeline infrastructure based upon pipeline economics.

7.2.2.1 Compliance Costs for Oil and Gas Exploration and Production

As the NSPS affects new emissions sources, we chose to estimate impacts on new exploration and development projects by adding costs of environmental regulation to the algorithm that evaluates the profitability of new projects. Additional NSPS costs associated with reduced emission completions and future recompletions for new wells are added to drilling, completion, and stimulation costs, as these are, in effect, associated with activities that occur within a single time period, although they may be repeated periodically, as in the case of recompletions. Costs required for reduced emissions recompletions on existing wells are added to stimulation expenses for existing wells exclusively. Other costs are operations and maintenance-type costs and are added to fixed operation and maintenance (O&M) expenses associated with new projects. The one-shot and continuing O&M expenses are estimated and entered on a per well basis, depending on whether the costs would apply to oil wells, natural gas wells, both oil and natural gas wells, or a subset of either. We base the per well cost estimates on the engineering costs including revenues from additional product recovery. This approach is appropriate given the structure of the NEMS algorithm that estimates the net present value of drilling projects.

One concern in basing the regulatory costs inputs into NEMS on the net cost of the compliance activity (estimated annualized cost of compliance minus estimated revenue from product recovery) is that potential barriers to obtaining capital may not be adequately incorporated in the model. However, in general, potential barriers to obtaining additional capital should be reflected in the annualized cost via these barriers increasing the cost of capital. With this in mind, assuming the estimates of capital costs and product recovery are valid, the NEMS results will reflect barriers to obtaining the retired capital. A caveat to this is that the estimated unit-level capital costs of controls which are newly required at a national-level as a result of the proposed regulation—RECs, for example—may not incorporate potential additional transitional costs as the supply of control equipment adjusts to new demand.

Table 7-1 shows the incremental O&M expenses that accrue to new drilling projects as a result of producers having to comply with the relevant NSPS option. We estimate those costs as a function of new wells expected to be drilled in a representative year. To arrive at estimates of

the per well costs, we first identify which emissions reductions will apply primarily to crude oil wells, to natural gas wells, or to both crude oil and natural gas wells. Based on the baseline projections of successful completions in 2015, we used 19,097 new natural gas wells and 12,193 new oil wells as the basis of these calculations. We then divide the estimated compliance costs for the given emissions point (from Table 3-3) by the appropriate number of expected new wells in the year of analysis. The result yields an approximation of a per well compliance costs. We assume this approximation is representative of the incremental cost faced by a producer when evaluating a prospective drilling project.

Like the engineering analysis, we assume that hydraulically fractured well completions and recompletions will be required of wells drilled into tight sand, shale gas, and coalbed methane formations. While costs for well recompletions reflect the cost of a single recompletion, the engineering cost analysis assumed that one in ten new wells drilled after the implementation of the promulgation and implementation of the NSPS are completed using hydraulic fracturing will receive a recompletion in any given year using hydraulic fracturing. Meanwhile, within NEMS, wells are assumed to be stimulated every five years. We assume these more frequent stimulations are less intensive than stimulation using hydraulic fracturing but add costs such that the recompletions costs reflect the same assumptions as the engineering analysis. In entering compliance costs into NEMS, we also account for reduced emissions completions, completion combustion, and recompletions performed in absence of the regulation, using the same assumptions as the engineering costs analysis (Table 7-2).

Table 7-1 Summary of Additional Annualized O&M Costs (on a Per New Well Basis) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Well Costs (2008$)			Wells Applied To in NEMS
		Option 1	Option 2 (Proposed)	Option 3	
Equipment Leaks					
Well Pads	Subpart VV	Not in Option	Not in Option	$3,552	Oil and Gas
Gathering and Boosting Stations	Subpart VV	Not in Option	Not in Option	$806	Gas
Processing Plants	Subpart VVa	Not in Option	$56	$56	None
Transmission Compressor Stations	Subpart VV	Not in Option	Not in Option	$320	Gas
Reciprocating Compressors					
Well Pads	Annual Monitoring/ Maintenance	Not in Option	Not in Option	Not in Option	None
Gathering/Boosting Stations	AMM	$17	$17	$17	Gas
Processing Plants	AMM	$12	$12	$12	Gas
Transmission Compressor Stations	AMM	$19	$19	$19	Gas
Underground Storage Facilities	AMM	$1	$1	$1	Gas
Centrifugal Compressors					
Processing Plants	Dry Seals/Route to Process or Control	-$113	-$113	-$113	Gas
Transmission Compressor Stations	Dry Seals/Route to Process or Control	-$62	-$62	-$62	Gas
Pneumatic Controllers -					
Oil and Gas Production	Low Bleed/Route to Process	-$698	-$698	-$698	Oil and Gas
Natural Gas Transmission and Storage	Low Bleed/Route to Process	$0.10	$0.10	$0.10	Gas
Storage Vessels					
High Throughput	95% control	$143	$143	$143	Oil and Gas
Low Throughput	95% control	Not in Option	Not in Option	Not in Option	None

Table 7-2 Summary of Additional Per Completion/Recompletion Costs (2008$) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Completion/Recompletion Costs (2008$) Option 1	Option 2 (proposed)	Option 3	Wells Applied To in NEMS
Well Completions					
Hydraulically Fractured Gas Wells	REC	-$1,275	-$1,275	-$1,275	New Tight Sand/ Shale Gas/CBM
Conventional Gas Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Oil Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Well Recompletions					
Hydraulically Fractured Gas Wells (post-NSPS wells)	REC	-$1,535	-$1,535	-$1,535	Existing Tight Sand/ Shale Gas /Coalbed Methane
Hydraulically Fractured Gas Wells (existing wells)	REC	Not in Option	-$1,535	-$1,535	Existing Tight Sand/ Shale Gas /Coalbed Methane
Conventional Gas Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Oil Wells	Combustion	Not in Option	Not in Option	Not in Option	None

7.2.2.2 Adding Averted Methane Emissions into Natural Gas Production

A significant benefit of controlling VOC emissions from oil and natural gas production is that methane that would otherwise be lost to the atmosphere can be directed into the natural gas production stream. We chose to model methane capture in NEMS as an increase in natural gas industry productivity, ensuring that, within the model, natural gas reservoirs are not decremented by production gains from methane capture. We add estimates of the quantities of methane captured (or otherwise not vented or combusted) to the base quantities that the OGSM model supplies to the NGTDM model. We subdivide the estimates of commercially valuable averted emissions by region and well type in order to more accurately portray the economics of implementing the environmental technology. Adding the averted methane emissions in this manner has the effect of moving the natural gas supply curve to the right an increment consistent with the technically achievable emissions transferred into the production stream as a result of the proposed NSPS.

For all control options, with the exception of recompletions on existing wells, we enter the increased natural gas recovery into NEMS on a per-well basis for new wells, following an

estimation procedure similar to that of entering compliance costs into NEMS on a per well basis for new wells. Because each NSPS Option is composed of a different suite of emissions controls, the per-well natural gas recovery value for new wells is different across wells. For Option 1, we estimate that natural gas recovery is 5,739 Mcf per well. For Option 2 and Option 3, we estimate that natural gas recovery is 5,743 Mcf per well. We make a simplifying assumption that natural gas recovery accruing to new wells accrues to new wells in shale gas, tight sands, and CBM fields. We make these assumptions because new wells in these fields are more likely to satisfy criteria such that RECs are required, which contributed that large majority of potential natural gas recovery. Note that these per well natural gas recovery is lower than the per well estimate when RECs are implemented. The estimate is lower because we account for emissions that are combusted, RECs that are implemented absent Federal regulation, as well as the likelihood that natural gas is used during processing and transmission or reinjected.

We treat the potential natural gas recovery associated with recompletions of existing wells (in proposed Option 2 and Option 3) differently in that we estimated the natural gas recovery by natural gas resource type and NSPS Option based on a combination of the engineering analysis and production patterns from the 2011 Annual Energy Outlook. We estimate that additional natural gas product recovered by recompleting existing wells in proposed Option 2 and Option 3 to be 78.7 bcf, with 38.4 bcf accruing to shale gas, 31.4 bcf accruing to tight sands, and 8.9 bcf accruing to CBM, respectively. This quantity is distributed within the NGTDM to reflect regional production by resource type.

7.2.2.3 Fixing Canadian Drilling Costs to Baseline Path

Domestic drilling costs serve as a proxy for Canadian drilling costs in the Canadian oil and natural gas sub-model within the NGTDM. This implies that, without additional modification, additional costs imposed by a U.S. regulation will also impact drilling decisions in Canada. Changes in international oil and gas trade are important in the analysis, as a large majority of natural gas imported into the U.S. originates in Canada. To avoid this problem, we fixed Canadian drilling costs using U.S. drilling costs from the baseline scenario. This solution enables a more accurate analysis of U.S.-Canada energy trade, as increased drilling costs in the U.S. as a result of environmental regulation serve to increase Canada's comparative advantage.

7.2.3 Energy System Impacts

As mentioned earlier, we estimate impacts to drilling activity, reserves, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas, as well as whether and to what extent the NSPS might alter the mix of fuels consumed at a national level. In each of these estimates, we present estimates for the baseline year of 2015 and results for the three NSPS options. For context, we provide estimates of production activities in 2011.

7.2.3.1 Impacts on Drilling Activities

Because the potential costs of the NSPS options are concentrated in production activities, we first report estimates of impacts on crude oil and natural gas drilling activities and production and price changes at the wellhead. Table 7-3 presents estimates of successful wells drilled in the U.S. in 2015, the analysis year, for the three NSPS options and in the baseline.

Table 7-3 Successful Oil and Gas Wells Drilled, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Successful Wells Drilled					
Natural Gas	16,373	19,097	19,191	18,935	18,872
Crude Oil	10,352	11,025	11,025	11,025	11,028
Total	**26,725**	**30,122**	**30,216**	**29,960**	**29,900**
% Change in Successful Wells Drilled from Baseline					
Natural Gas			0.49%	-0.85%	-1.18%
Crude Oil			0.00%	0.00%	0.03%
Total			**0.31%**	**-0.54%**	**-0.74%**

We estimate that the number of successful natural gas wells drilled increases slightly for Option 1, while the number of successful crude oil wells drilled does not change. In Options 2, where costs of the natural gas processing plants equipment leaks standard and REC requirements for existing wells apply, natural gas wells drilling is forecast to decrease less than 1 percent, while crude oil drilling does not change. For Option 3, where the addition of an additional equipment

leak standards add to the incremental costs, natural gas well drilling is estimated to decrease about 1.2%. The number of successful crude oil wells drilled under Option 3 increases very slightly. While it may seem counter-intuitive that the number of successful crude wells increased as costs increase, it is important to note that crude oil and natural gas drilling compete with each other for factors of production, such as labor and material. The environmental compliance costs of the NSPS options predominantly affect natural gas drilling. As natural gas drilling declines, for example, as a result of increased compliance costs, crude oil drilling may increase because of the increased availability of labor and material, as well as the likelihood that crude oil can substitute for natural gas to some extent.

Table 7-4 presents the forecast of successful wells by well type, for onshore drilling in the lower 48 states. The results show that conventional well drilling is unaffected by the regulatory options, as reduced emission completion and completion combustion requirements are directed not toward wells in conventional reserves but toward wells that are hydraulically fractured, the wells in so-called unconventional reserves. The impacts on drilling tight sands, shale gas, and coalbed methane vary by option.

Table 7-4 Successful Wells Drilled by Well Type (Onshore, Lower 48 States), NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Successful Wells Drilled					
Conventional Gas Wells	7,267	7,607	7,607	7,607	7,607
Tight Sands	2,441	2,772	2,791	2,816	2,780
Shale Gas	5,007	7,022	7,074	6,763	6,771
Coalbed Methane	1,593	1,609	1,632	1,662	1,627
Total	**16,308**	**19,010**	**19,104**	**18,849**	**18,785**
% Change in Successful Wells Drilled from Baseline					
Conventional Gas Wells			0.00%	0.00%	0.00%
Tight Sands			0.70%	1.60%	0.29%
Shale Gas			0.74%	-3.68%	-3.57%
Coalbed Methane			1.44%	3.28%	1.09%
Total			**0.50%**	**-0.85%**	**-1.18%**

Well drilling in tight sands is estimated to increase slightly from the baseline under all three options, 0.70 percent, 1.60 percent, and 0.29% for Options 1, 2, and 3, respectively. Wells in CBM reserves are also estimated to increase from the baseline under all three options, or 1.44 percent, 3.28 percent, and 1.09 percent for Options 1, 2, and 3, respectively. However, drilling in shale gas is forecast to decline from the baseline under Options 2 and 3, by 3.68 percent and 3.57 percent, respectively.

7.2.3.2 Impacts on Production, Prices, and Consumption

Table 7-5 shows estimates of the changes in the domestic production of natural gas and crude oil under the NSPS options, as of 2015. Domestic crude oil production is not forecast to change under any of the three regulatory options, again because impacts on crude oil drilling of the NSPS are expected to be negligible.

Table 7-5 Annual Domestic Natural Gas and Crude Oil Production, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Domestic Production					
Natural Gas (trillion cubic feet)	21.05	22.43	22.47	22.45	22.44
Crude Oil (million barrels/day)	5.46	5.81	5.81	5.81	5.81
% Change in Domestic Production from Baseline					
Natural Gas			0.18%	0.09%	0.04%
Crude Oil			0.00%	0.00%	0.00%

Natural gas production, on the other hand, increases under all three regulatory options for the NSPS from the baseline. A main driver for these increases is the additional natural gas recovery engendered by the control requirements. Another driver for the increases under Option 1 is the increase in natural gas well drilling. While we showed earlier that natural gas drilling is estimated to decline under Options 2 and 3, the increased natural gas recovery is sufficient to offset the production loss from relatively fewer producing wells.

For the proposed option, the NEMS analysis shown in Table 7-5 estimates a 20 bcf increase in domestic natural gas production. This amount is less than the amount estimated in the engineering analysis to be captured by emissions controls implemented as a result of the

proposed NSPS (approximately 180 bcf). This difference is because NEMS models the adjustment of energy markets to the now relatively more efficient natural gas production sector. At the new natural gas supply and demand equilibrium in 2015, the modeling estimates 20 bcf more gas is produced at a relatively lower wellhead price (which will be presented momentarily). However, at the new equilibrium, producers implementing emissions controls still capture and sell approximately 180 bcf of natural gas. For example, as shown in Table 7-4, about 11,200 new unconventional natural gas wells are completed under the proposed NSPS; using assumptions from the engineering cost analysis about RECs required under State regulations and exploratory wells exempted from REC requirements, about 9,000 NSPS-required RECs would be performed on new natural gas well completions, according to the NEMS analysis. This recovered natural gas substitutes for natural gas that would be produced from the ground absent the rule. In effect, then, about 160 bcf of natural gas that would have been extracted and emitted into the atmosphere is left in the formation for future extraction.

As we showed for natural gas drilling, Table 7-6 shows natural gas production from onshore wells in the lower 48 states by type of well, predicted for 2015, the analysis year. Production from conventional natural gas wells and CBM wells are estimated to increase under all NSPS regulatory options. Production from shale gas reserves is estimated to decrease under Options 2 and 3, however, from the baseline projection. Production from tight sands is forecast to decline slightly under Option 1.

Table 7-6 Natural Gas Production by Well Type (Onshore, Lower 48 States), NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Natural Gas Production by Well Type (trillion cubic feet)					
Conventional Gas Wells	4.06	3.74	3.75	3.76	3.76
Tight Sands	5.96	5.89	5.87	6.00	6.00
Shale Gas	5.21	7.20	7.26	7.06	7.06
Coalbed Methane	1.72	1.67	1.69	1.72	1.71
Total	**16.95**	**18.51**	**18.57**	**18.54**	**18.53**
% Change in Natural Gas Production by Well Type from Baseline					
Conventional Gas Wells			0.32%	0.42%	0.48%
Tight Sands			-0.43%	1.82%	1.72%
Shale Gas			0.73%	-1.97%	-1.93%
Coalbed Methane			1.07%	2.86%	2.60%
Total			0.31%	0.16%	0.13%

Note: Totals may not sum due to independent rounding.

Overall, of the regulatory options, the proposed Option 2 is estimated to have the highest natural gas production from onshore wells in the lower 48 states, showing a 1.2% increase over the baseline projection.

Table 7-7 presents estimates of national average wellhead natural gas and crude oil prices for onshore production in the lower 48 states, estimated for 2015, the year of analysis. All NSPS options show a decrease in wellhead natural gas and crude oil prices. The decrease in wellhead natural gas price form the baseline is attributable largely to the increased productivity of natural gas wells as a result of capturing a portion of completion emissions (in Options 1, 2, and 3) and in capturing recompletion emissions (in Options 2 and 3).

Table 7-7 Lower 48 Average Natural Gas and Crude Oil Wellhead Price, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Lower 48 Average Wellhead Price					
Natural Gas (2008$ per Mcf)	4.07	4.22	4.18	4.18	4.19
Crude Oil (2008$ per barrel)	83.65	94.60	94.59	94.58	94.58
% Change in Lower 48 Average Wellhead Price from Baseline					
Natural Gas			-0.94%	-0.94%	-0.71%
Crude Oil			-0.01%	-0.02%	-0.02%

Table 7-8 presents estimates of the price of natural gas to final consumers in 2008 dollars per million BTU. The production price decreases estimated across NSPS are largely passed on to consumers but distributed unequally across consuming sectors. Electric power sector consumers of natural gas are estimated to receive the largest price decrease while the transportation and residential sectors are forecast to receive the smallest price decreases.

Table 7-8 Delivered Natural Gas Prices by Sector (2008$ per million BTU), 2015, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Delivered Prices (2008$ per million BTU)					
Residential	10.52	10.35	10.32	10.32	10.33
Commercial	9.26	8.56	8.52	8.53	8.54
Industrial	4.97	5.08	5.05	5.05	5.06
Electric Power	4.81	4.77	4.73	4.74	4.75
Transportation	12.30	12.24	12.20	12.22	12.22
Average	**6.76**	**6.59**	**6.55**	**6.57**	**6.57**
% Change in Delivered Prices from Baseline					
Residential			**-0.29%**	**-0.29%**	**-0.19%**
Commercial			**-0.47%**	**-0.35%**	**-0.23%**
Industrial			**-0.59%**	**-0.59%**	**-0.39%**
Electric Power			**-0.84%**	**-0.63%**	**-0.42%**
Transportation			**-0.33%**	**-0.16%**	**-0.16%**
Average			**-0.60%**	**-0.41%**	**-0.30%**

Final consumption of natural gas is also estimated to increase in 2015 from the baseline under all NSPS options, as is shown on Table 7-9. Like delivered price, the consumption shifts are distributed differently across sectors.

Table 7-9 Natural Gas Consumption by Sector, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Consumption (trillion cubic feet)					
Residential	4.76	4.81	4.81	4.81	4.81
Commercial	3.22	3.38	3.38	3.38	3.38
Industrial	6.95	8.05	8.06	8.06	8.06
Electric Power	7.00	6.98	7.00	6.98	6.97
Transportation	0.03	0.04	0.04	0.04	0.04
Pipeline Fuel	0.64	0.65	0.65	0.66	0.66
Lease and Plant Fuel	1.27	1.20	1.21	1.21	1.21
Total	**23.86**	**25.11**	**25.15**	**25.14**	**25.13**
% Change in Consumption from Baseline					
Residential			0.00%	0.00%	0.00%
Commercial			0.00%	0.00%	0.00%
Industrial			0.12%	0.12%	0.12%
Electric Power			0.29%	0.00%	-0.14%
Transportation			0.00%	0.00%	0.00%
Pipeline Fuel			0.00%	1.54%	1.54%
Lease and Plant Fuel			0.83%	0.83%	0.83%
Total			**0.16%**	**0.12%**	**0.08%**

Note: Totals may not sum due to independent rounding.

7.2.3.3 Impacts on Imports and National Fuel Mix

The NEMS modeling shows that impacts from all NSPS options are not sufficiently large to affect the trade balance of natural gas. As shown in Table 7-10, estimates of crude oil and natural gas imports do not vary from the baseline in 2015 for each regulatory option.

Table 7-10 Net Imports of Natural Gas and Crude Oil, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Net Imports					
Natural Gas (trillion cubic feet)	2.75	2.69	2.69	2.69	2.69
Crude Oil (million barrels/day)	9.13	8.70	8.70	8.70	8.70
% Change in Net Imports					
Natural Gas			0.00%	0.00%	0.00%
Crude Oil			0.00%	0.00%	0.00%

Table 7-11 evaluates estimates of energy consumption by energy type at the national level for 2015, the year of analysis. All three NSPS options are estimated to have small effects at the national level. For Option 1, we estimate an increase in 0.02 quadrillion BTU in 2015, a 0.02 percent increase. The percent contribution of natural gas and biomass is projected to increase, while the percent contribution of liquid fuels and coal is expected to decrease under Option 1. Meanwhile, under the proposed Options 2, total energy consumption is also forecast to rise 0.02 quadrillion BTU, with increase coming from natural gas primarily, with an additional small increase in coal consumption. Under Option 3, total energy consumption is forecast to rise 0.01 quadrillion BTU, or 0.01%, with a slight decrease in liquid fuel consumption from the baseline, but increases in natural gas and coal consumption.

Table 7-11 Total Energy Consumption by Energy Type (Quadrillion BTU), NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Consumption (quadrillion BTU)					
Liquid Fuels	37.41	39.10	39.09	39.10	39.09
Natural gas	24.49	25.77	25.82	25.79	25.79
Coal	20.42	19.73	19.71	19.74	19.74
Nuclear Power	8.40	8.77	8.77	8.77	8.77
Hydropower	2.58	2.92	2.92	2.92	2.92
Biomass	2.98	3.27	3.28	3.27	3.27
Other Renewable Energy	1.72	2.14	2.14	2.14	2.14
Other	0.30	0.31	0.31	0.31	0.31
Total	**98.29**	**102.02**	**102.04**	**102.04**	**102.03**
% Change in Consumption from Baseline					
Liquid Fuels			-0.03%	0.00%	-0.03%
Natural Gas			0.19%	0.08%	0.08%
Coal			-0.10%	0.05%	0.05%
Nuclear Power			0.00%	0.00%	0.00%
Hydropower			0.00%	0.00%	0.00%
Biomass			0.31%	0.00%	0.00%
Other Renewable Energy			0.00%	0.00%	0.00%
Other			0.00%	0.00%	0.00%
Total			**0.02%**	**0.02%**	**0.01%**

Note: Totals may not sum due to independent rounding.

With the national profile of energy consumption estimated to change slightly under the regulatory options in 2015, the year of analysis, it is important to examine whether aggregate energy-related CO_2-equivalent greenhouse gas (GHG) emissions also shift. A more detailed discussion of changes in CO_2-equivalent GHG emissions from a baseline is presented within the benefits analysis in Section 4. Here, we present a single NEMS-based table showing estimated changes in energy-related "consumer-side" GHG emissions. We use the terms "consumer-side" emissions to distinguish emissions from the consumption of fuel from emissions specifically associated with the extraction, processing, and transportation of fuels in the oil and natural gas sector under examination in this RIA. We term the emissions associated with extraction, processing, and transportation of fuels "producer-side" emissions.

Table 7-12 Modeled Change in Energy-related "Consumer-Side" CO_2-equivalent GHG Emissions

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Energy-related CO_2-equivalent GHG Emissions (million metric tons CO_2-equivalent)					
Petroleum	2,359.59	2,433.60	2,433.12	2,433.49	2,433.45
Natural Gas	1,283.78	1,352.20	1,354.47	1,353.19	1,352.87
Coal	1,946.02	1,882.08	1,879.84	1,883.24	1,883.30
Other	11.99	11.99	11.99	11.99	11.99
Total	**5,601.39**	**5,679.87**	**5,679.42**	**5,681.91**	**5,681.61**
% Change in Energy-related CO_2-equivalent GHG Emissions from Baseline					
Petroleum			-0.02%	0.00%	-0.01%
Natural Gas			0.17%	0.07%	0.05%
Coal			-0.12%	0.06%	0.06%
Other			0.00%	0.00%	0.00%
Total			**-0.01%**	**0.04%**	**0.03%**

Note: Excludes "producer-side" emissions and emissions reductions estimated to result from NSPS alternatives. Totals may not sum due to independent rounding.

As is shown in Table 7-12, NSPS Option 1 is predicted to slightly decrease aggregate consumer-side energy-related CO_2-equivalent GHG emissions, by about 0.01 percent, while the mix of emissions shifts slightly away from coal and petroleum toward natural gas. Proposed Options 2 and 3 are estimated to increase consumer-side aggregate energy-related CO_2-equivalent GHG emissions by about 0.04 and 0.03 percent, respectively, mainly because consumer-side emissions from natural gas and coal combustion increase slightly.

7.3 Employment Impact Analysis

While a standalone analysis of employment impacts is not included in a standard cost-benefit analysis, such an analysis is of particular concern in the current economic climate of sustained high unemployment. Executive Order 13563, states, "Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation" (emphasis added). Therefore, we seek to inform the discussion of labor demand and job impacts by providing an estimate of the employment impacts of the proposed regulations using labor requirements for the installation, operation, and

maintenance of control requirements, as well as reporting and recordkeeping requirements. Unlike several recent RIAs, however, we do not provide employment impacts estimates based on the study by Morgenstern et al. (2002); we discuss this decision after presenting estimates of the labor requirements associated with reporting and recordkeeping and the installation, operation, and maintenance of control requirements.

7.3.1 Employment Impacts from Pollution Control Requirements

Regulations set in motion new orders for pollution control equipment and services. New categories of employment have been created in the process of implementing regulations to make our air safer to breathe. When a new regulation is promulgated, a response of industry is to order pollution control equipment and services in order to comply with the regulation when it becomes effective. Revenue and employment in the environmental technology industry have grown steadily between 2000 and 2008, reaching an industry total of approximately $300 billion in revenues and 1.7 million employees in 2008.[52] While these revenues and employment figures represent gains for the environmental technologies industry, they are costs to the regulated industries required to install the equipment. Moreover, it is not clear the 1.7 million employees in 2008 represent new employment as opposed to workers being shifted from the production of goods and services to environmental compliance activities.

Once the equipment is installed, regulated firms hire workers to operate and maintain the pollution control equipment – much like they hire workers to produce more output. Morgenstern et al. (2002) examined how regulated industries respond to regulation. The authors found that, on average for the industries they studied, employment increases in regulated firms. Of course, these firms may also reassign existing employees to perform these activities.

[52] In 2008, the industry totaled approximately $315 billion in revenues and 1.9 million employees including indirect employment effects, pollution abatement equipment production employed approximately 4.2 million workers in 2008. These indirect employment effects are based on a multiplier for indirect employment = 2.24 (1982 value from Nestor and Pasurka - approximate middle of range of multipliers 1977-1991). Environmental Business International (EBI), Inc., San Diego, CA. Environmental Business Journal, monthly (copyright). http://www.ebiusa.com/ EBI data taken from the Department of Commerce International Trade Administration Environmental Industries Fact Sheet from April 2010: http://web.ita.doc.gov/ete/eteinfo.nsf/068f3801d047f26e85256883006ffa54/4878b7e2fc08ac6d85256883006c452c?OpenDocument

Environmental regulations support employment in many basic industries. In addition to the increase in employment in the environmental protection industry (via increased orders for pollution control equipment), environmental regulations also support employment in industries that provide intermediate goods to the environmental protection industry. The equipment manufacturers, in turn, order steel, tanks, vessels, blowers, pumps, and chemicals to manufacture and install the equipment. Bezdek et al. (2008) found that investments in environmental protection industries create jobs and displace jobs, but the net effect on employment is positive.

The focus of this part of the analysis is on labor requirements related to the compliance actions of the affected entities within the affected sector. We do not estimate any potential changes in labor outside of the oil and natural gas sector. This analysis estimates the employment impacts due to the installation, operation, and maintenance of control equipment, as well as employment associated with new reporting and recordkeeping requirements.

It is important to highlight that unlike the typical case where to reduce a bad output (i.e., emissions) a firm often has to reduce production of the good output, many of the emission controls required by the proposed NSPS will simultaneously increase production of the good output and reduce production of bad outputs. That is, these controls jointly produce environmental improvements and increase output in the regulated sector. New labor associated with implementing these controls to comply with the new regulations can also be viewed as additional labor increasing output while reducing undesirable emissions.

No estimates of the labor used to manufacture or assemble pollution control equipment or to supply the materials for manufacture or assembly are included because U.S. EPA does not currently have this information. The employment analysis uses a bottom-up engineering-based methodology to estimate employment impacts. The engineering cost analysis summarized in this RIA includes estimates of the labor requirements associated with implementing the proposed regulations. Each of these labor changes may either be required as part of an initial effort to comply with the new regulation or required as a continuous or annual effort to maintain compliance. We estimate up-front and continual, annual labor requirements by estimating hours of labor required and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). We note that this type of FTE estimate

cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

In other employment analyses U.S. EPA distinguished between employment changes within the regulated industry and those changes outside the regulated industry (e.g. a contractor from outside the regulated facility is employed to install a control device). For this regulation however, the structure of the industry makes this difficult. The mix of in-house versus contracting services used by firms is very case-specific in the oil and natural gas industry. For example, sometimes the owner of the well, processing plant, or transmission pipelines uses in–house employees extensively in daily operations, while in other cases the owner relies on outside contractors for many of these services. For this reason, we make no distinction in the quantitative estimates between labor changes within and outside of the regulated sector.

The results of this employment estimate are presented in Table 7-13 for the proposed NSPS and in Table 7-14 for the proposed NESHAP amendments. The tables breaks down the installation, operation, and maintenance estimates by type of pollution control evaluated in the RIA and present both the estimated hours required and the conversion of this estimate to FTE. For both the proposed NSPS and NESHAP amendments, reporting and recordkeeping requirements were estimated for the entire rules rather than by anticipated control requirements; the reporting and recordkeeping estimates are consistent with estimates EPA submitted as part of its Information Collection Request (ICR).

The up-front labor requirement is estimated at 230 FTEs for the proposed NSPS and about 120 FTEs for the proposed NESHAP amendments. These up-front FTE labor requirements can be viewed as short-term labor requirements required for affected entities to comply with the new regulation. Ongoing requirements are estimated at about 2,400 FTEs for the proposed NSPS and about 102 FTEs for the proposed NESHAP amendments. These ongoing FTE labor requirements can be viewed as sustained labor requirements required for affected entities to continuously comply with the new regulation

Two main categories contain the majority of the labor requirements for the proposed rules: implementing reduced emissions completions (RECs) and reporting and recordkeeping

requirements for the proposed NSPS. Also, note that pneumatic controllers have no up-front or continuing labor requirements. While the controls do require labor for installation, operation, and maintenance, the required labor is less than that of the controllers that would be used absent the regulation. In this instance, we assume the incremental labor requirements are zero.

Implementing RECs are estimated to require about 2,230 FTE, over 90 percent of the total continuing labor requirements for the proposed NSPS.[53] We denote REC-related requirements as continuing, or annual, as the REC requirements will in fact recur annually, albeit at different wells each year. The REC requirements are associated with certain new well completions or existing well recompletions, which while individual completions occur over a short period of time (days to a few weeks), new wells and other existing wells are completed or recompleted annually. Because of these reasons, we assume the REC-related labor requirements are annual.

7.3.2 Employment Impacts Primarily on the Regulated Industry

In previous RIAs, we transferred parameters from a study by Morgenstern et al. (2002) to estimate employment effects of new regulations. (See, for example, the Regulatory Impact Analysis for the recently finalized Industrial Boilers and CISWI rulemakings, promulgated on February 21, 2011). The fundamental insight of Morgenstern, et al. is that environmental regulations can be understood as requiring regulated firms to add a new output (environmental quality) to their product mixes. Although legally compelled to satisfy this new demand, regulated firms have to finance this additional production with the proceeds of sales of their other (market) products. Satisfying this new demand requires additional inputs, including labor, and may alter the relative proportions of labor and capital used by regulated firms in their production processes.

Morgenstern et al. concluded that increased abatement expenditures in these industries generally do not cause a significant change in employment. Using plant-level Census

[53] As shown on earlier in this section, we project that the number of successful natural gas wells drilled in 2015 will decline slightly from the baseline projection. Therefore, there may be small employment losses in drilling-related employment that partly offset gains in employment from compliance-related activities.

information between the years 1979 and 1991, Morgenstern et al. estimate the size of each effect for four polluting and regulated industries (petroleum refining, plastic material, pulp and paper, and steel). On average across the four industries, each additional $1 million (1987$) spending on pollution abatement results in a (statistically insignificant) net increase of 1.55 (+/- 2.24) jobs. As a result, the authors conclude that increases in pollution abatement expenditures do not necessarily cause economically significant employment changes.

For this version of RIA for the proposed NSPS and NESHAP amendments, however, we chose not to quantitatively estimate employment impacts using Morgenstern et al. because of reasons specific to the oil and natural gas industry and proposed rules. We believe the transfer of parameter estimates from the Morgenstern et al. study to the proposed NSPS and NESHAP amendments is beyond the range of the study for two reasons.

Table 7-13 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Proposed NSPS Option in 2015

Source/Emissions Point	Emissions Control	Projected No. of Affected Units	Per Unit Up- Front Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total Up- Front Labor Estimate (hours)	Total Annual Labor Estimate (hours)	Up-Front Full-Time Equivalent	Annual Full-Time Equivalent
Well Completions								
Hydraulically Fractured Gas Wells	Reduced Emissions Completion (REC)	9,313	0	218	0	2,025,869	0.0	974.0
Hydraulically Fractured Gas Wells	Combustion	446	0	22	0	9,626	0.0	4.6
Well Recompletions								
Hydraulically Fractured Gas Wells (pre-NSPS wells)	REC	12,050	0	218	0	2,621,126	0.0	1,260.2
Equipment Leaks								
Processing Plants	NSPS Subpart VVA	29	587	887	17,023	25,723	8.2	12.4
Reciprocating Compressors								
Gathering/Boosting Stations	AMM	210	1	1	210	210	0.1	0.1
Processing Plants	AMM	375	1	1	375	375	0.2	0.2
Transmission Compressor Stations	AMM	199	1	1	199	199	0.1	0.1
Underground Storage Facilities	AMM	9	1	1	9	9	0.0	0.0
Centrifugal Compressors								
Processing Plants	Dry Seals/Route to Process or Control	16	355	0	5,680	0	2.7	0.0
Transmission Compressor Stations	Dry Seals/Route to Process or Control	14	355	0	4,970	0	2.4	0.0
Pneumatic Controllers								
Oil and Gas Production	Low Bleed/Route to Process	13,632	0	0	0	0	0.0	0.0
Natural Gas Trans. and Storage	Low Bleed/Route to Process	67	0	0	0	0	0.0	0.0
Storage Vessels								
High Throughput	95% control	304	271	190	82,279	57,582	39.6	27.7
Reporting and Recordkeeping for Complete NSPS		---	---	---	360,443	201,342	173.3	96.8
TOTAL		**---**	**---**	**---**	**471,187**	**4,942,060**	**226.5**	**2,376.0**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 7-14 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Proposed NESHAP Amendments in 2015

Source/Emissions Point	Emissions Control	Projected No. of Affected Units	Per Unit One-time Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total One-Time Labor Estimate (hours)	Total Annual Labor Estimate (hours)	One-time Full-Time Equivalent	Annual Full-Time Equivalent
Small Glycol Dehydrators								
Production	Combustion devices, recovery devices, process modifications	115	27	285	3,108	32,821	1.5	15.8
Transmission	Combustion devices, recovery devices, process modifications	19	27	285	513	5,423	0.2	2.6
Storage Vessels								
Production	Combustion devices, recovery devices	674	311	198	209,753	133,231	100.8	64.1
Reporting and Recordkeeping for Complete NESHAP Amendments		---	---	---	36,462	39,923	17.5	19.2
TOTAL		**---**	**--**	**---**	**249,836**	**211,398**	**120.1**	**101.6**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

First, the possibility that the revenues producers are estimated to receive from additional natural gas recovery as a result of the proposed NSPS might offset the costs of complying with the rule presents challenges to estimating employment effects (see Section 3.2.2.1 of the RIA for a detailed discussion of the natural gas recovery). The Morgenstern et al. paper, for example, is intended to analyze the impact of environmental compliance expenditures on industry employment levels, and it may not be appropriate to draw on their demand and net effects when compliance costs are expected to be negative.

Second, the proposed regulations primarily affect the natural gas production, processing, and transmission segments of the industry. While the natural gas processing segment of the oil and natural gas industry is similar to petroleum refining, which is examined in Morgenstern et al., the production side of the oil and natural gas (drilling and extraction, primarily) and natural gas pipeline transmission are not similar to petroleum refining. Because of the likelihood of negative compliance costs for the proposed NSPS and the segments of the oil and natural gas industry affected by the proposals are not examined by Morgenstern et al., we decided not to use the parameters estimated by Morgenstern et al. to estimate within-industry employment effects for the proposed oil and natural gas NESHAP amendments and NSPS.

That said, the likelihood of additional natural gas recovery is an important component of the market response to the rule, as it is expected that this additional natural gas recovery will reduce the price of natural gas. Because of the estimated fall in prices in the natural gas sector due to the proposed NSPS, prices in other sectors that consume natural gas are likely drop slightly due to the decrease in energy prices. This small production increase and price decrease may have a slight stimulative effect on employment in industries that consume natural gas.

7.4 Small Business Impacts Analysis

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a

significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

After considering the economic impact of the proposed rules on small entities for both the NESHAP and NSPS, the screening analysis indicates that these proposed rules will not have a significant economic impact on a substantial number of small entities (or "SISNOSE"). The supporting analyses for these determinations are presented in this section of the RIA.

As discussed in previous sections of the economic impact analysis, under the proposed NSPS, some affected producers are likely to be able to recover natural gas that would otherwise be vented to the atmosphere, as well as recover saleable condensates that would otherwise be emitted. EPA estimates that the revenues from this additional natural gas product recovery will offset the costs of implementing control options implemented as a result of the Proposed NSPS. Because the total costs of the rule are likely to be more than offset by the revenues producers gain from increased natural gas recovery, we expect there will be no SISNOSE arising from the proposed NSPS. However, not all components of the proposed NSPS are estimated to have cost savings. Therefore, we analyze potential impacts to better understand the potential distribution of impacts across industry segments and firms. We feel taking this approach strengthens the determination that there will be no SISNOSE. Unlike the controls for the proposed NSPS, the controls evaluated under the proposed NESHAP amendments do not recover significant quantities of natural gas products.

7.4.1 Small Business National Overview

The industry sectors covered by the final rule were identified during the development of the engineering cost analysis. The U.S. Census Bureau's Statistics of U.S. Businesses (SUSB) provides national information on the distribution of economic variables by industry and enterprise size. The Census Bureau and the Office of Advocacy of the Small Business Administration (SBA) supported and developed these files for use in a broad range of economic analyses.[54] Statistics include the total number of establishments, and receipts for all entities in an industry; however, many of these entities may not necessarily be covered by the final rule. SUSB also provides statistics by enterprise employment and receipt size (Table 7-15 and Table 7-16).

[54]See http://www.census.gov/csd/susb/ and http://www.sba.gov/advocacy/ for additional details.

The Census Bureau's definitions used in the SUSB are as follows:

- *Establishmen*t: A single physical location where business is conducted or where services or industrial operations are performed.
- *Firm:* A firm is a business organization consisting of one or more domestic establishments in the same state and industry that were specified under common ownership or control. The firm and the establishment are the same for single-establishment firms. For each multi-establishment firm, establishments in the same industry within a state will be counted as one firm- the firm employment and annual payroll are summed from the associated establishments.
- *Receipts*: Receipts (net of taxes) are defined as the revenue for goods produced, distributed, or services provided, including revenue earned from premiums, commissions and fees, rents, interest, dividends, and royalties. Receipts exclude all revenue collected for local, state, and federal taxes.
- *Enterprise*: An enterprise is a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the sum of employment of all associated establishments.

Because the SBA's business size definitions (SBA, 2008) apply to an establishment's "ultimate parent company," we assumed in this analysis that the "firm" definition above is consistent with the concept of ultimate parent company that is typically used for SBREFA screening analyses, and the terms are used interchangeably.

Table 7-15 Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007

NAICS	NAICS Description	SBA Size Standard (effective Nov. 5, 2010)	Owned by Firms with: < 20 Employees	20-99 Employees	100-499 Employees	Total < 500 Employees	> 500 Employees	Total Firms
Number of Firms by Firm Size								
211111	Crude Petroleum and Natural Gas Extraction	500	5,759	455	115	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	77	9	12	98	41	139
213111	Drilling Oil and Gas Wells	500	1,580	333	97	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	63	12	9	84	42	126
Total Employment by Firm Size								
211111	Crude Petroleum and Natural Gas Extraction	500	21,170	16,583	17,869	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	372	305	1,198	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	5,972	13,787	16,893	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	241	382	1,479	2,102	22,581	24,683
Estimated Receipts by Firm Size ($1000)								
211111	Crude Petroleum and Natural Gas Extraction	500	12,488,688	15,025,443	17,451,805	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	209,640	217,982	1,736,706	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	1,101,481	2,460,301	3,735,652	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	332,177	518,341	1,448,020	2,298,538	18,498,143	20,796,681

Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007." <http://www.census.gov/econ/susb/>

Table 7-16 Distribution of Small and Large Firms by Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007

NAICS	NAICS Description	Total Firms	Percent of Firms: Small Businesses	Percent of Firms: Large Businesses	Percent of Firms: Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	6,424	98.5%	1.5%	100.0%
211112	Natural Gas Liquid Extraction	139	70.5%	29.5%	100.0%
213111	Drilling Oil and Gas Wells	2,059	97.6%	2.4%	100.0%
486210	Pipeline Transportation of Natural Gas	126	48.4%	51.6%	100.0%
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	133,286	41.7%	58.3%	100.0%
211112	Natural Gas Liquid Extraction	8,523	22.0%	78.0%	100.0%
213111	Drilling Oil and Gas Wells	106,426	34.4%	65.6%	100.0%
486210	Pipeline Transportation of Natural Gas	24,683	N/A*	N/A*	N/A*
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	194,107,252	23.2%	76.8%	100.0%
211112	Natural Gas Liquid Extraction	39,977,741	5.4%	94.6%	100.0%
213111	Drilling Oil and Gas Wells	23,848,238	30.6%	69.4%	100.0%
486210	Pipeline Transportation of Natural Gas	20,796,681	N/A*	N/A*	N/A*

Note: Employment and receipts could not be broken down between small and large businesses because of non-disclosure requirements.

Source: SBA

While the SBA and Census Bureau statistics provide informative broad contextual information on the distribution of enterprises by receipts and number of employees, it is also useful to additionally contrast small and large enterprises (where large enterprises are defined as those that are not small, according to SBA criteria) in the oil and natural gas industry. The summary statistics presented in previous tables indicate that there are a large number of relatively small firms and a small number of large firms. Given the majority of expected impacts of the proposed rules arises from well completion-related requirements, which impacts production activities, exclusively, some explanation of this particular market structure is warranted as it pertains to production and small entities. An important question to answer is whether there are particular roles that small entities serve in the production segment of the oil and natural gas industry that may be disproportionately affected by the proposed rules.

The first important broad distinction among firms is whether they are independent or integrated. Independent firms concentrate on exploration and production (E&P) activities, while integrated firms are vertically integrated and often have operations in E&P, processing, refining, transportation, and retail. To our awareness, there are no small integrated firms. Independent firms may own and operate wells or provide E&P-related services to the oil and gas industry. Since we are focused on evaluating potential impacts to small firms owning and operating new and existing hydraulically fractured wells, we should narrow down on this sector.

In our understanding, there is no single industry niche for small entities in the production segment of the industry since small operators have different business strategies and that small entities can own different types of wells. The organization of firms in oil and natural gas industry also varies greatly from firm to firm. Additionally, oil and natural gas resources vary widely geographically and can vary significantly within a single field.

Among many important roles, independent small operators historically pioneered exploration in new areas, as well as developed new technologies. By taking on these relatively large risks, these small entrepreneurs (wildcatters) have been critical sources of industrial innovation and opened up critical new energy supplies for the U.S. (HIS Global Insight). In recent decades, as the oil and gas industry has concentrated via mergers, many of these smaller firms have been absorbed into large firms.

Another critical role, which provides an interesting contrast to small firms pioneering new territory, is that smaller independents maintain and operate a large proportion of the Nation's low producing wells, which are also known as marginal or stripper wells (Duda et al. 2005). While marginal wells represent about 80 percent of the population of producing wells, they produce about 15 percent of domestic production, according to EIA (Table 7-17).

Table 7-17 Distribution of Crude Oil and Natural Gas Wells by Productivity Level, 2009

Type of Wells	Wells (no.)	Wells (%)	Production (MMbbl for oil and Bcf gas)	Production (%)
Crude Oil				
Stripper Wells (<15 boe per year)	310,552	85%	311	19%
Other Wells (>=15 boe per year)	52,907	15%	1,331	81%
Total Crude Oil Wells	**363,459**	**100%**	**1,642**	**100%**
Natural Gas				
Natural Gas Stripper Wells (<15 boe per year)	338,056	73%	2,912	12%
Other Natural Gas Wells (>=15 boe per year)	123,332	27%	21,048	88%
Total Natural Gas Wells	**461,388**	**100%**	**23,959**	**100%**

Source: U.S. Energy Information Administration, **Distribution of Wells by Production Rate Bracket.** <http://www.eia.gov/pub/oil_gas/petrosystem/us_table.html> Accessed 7/10/11.

Note: Natural gas production converted to barrels oil equivalent (boe) uses the conversion of 0.178 barrels of crude oil to 1000 cubic feet natural gas.

Many of these wells were likely drilled and initially operated by major firms (although the data are not available to quantify the percentage of wells initially drilled by small versus large producers). Well productivity levels typically follow a steep decline curve; high production in earlier years but sustained low production for decades. Because of relatively low overhead of maintaining and operating few relatively co-located wells, some small operators with a particular business strategy purchase low producing wells from the majors, who concentrate on new opportunities. As small operators have provided important technical innovation in exploration, small operators have also been sources of innovation in extending the productivity and lifespan of existing wells (Duda et al. 2005).

7.4.2 Small Entity Economic Impact Measures

The proposed Oil and Natural Gas NSPS and NESHAP amendments will affect the owners of the facilities that will incur compliance costs to control their regulated emissions. The owners, either firms or individuals, are the entities that will bear the financial impacts associated with these additional operating costs. The proposed rule has the potential to impact all firms owning affected facilities, both large and small.

The analysis provides EPA with an estimate of the magnitude of impacts the proposed NSPS and NESHAP amendments may have on the ultimate domestic parent companies that own facilities EPA expects might be impacted by the rules. The analysis focuses on small firms because they may have more difficulty complying with a new regulation or affording the costs associated with meeting the new standard. This section presents the data sources used in the screening analysis, the methodology we applied to develop estimates of impacts, the results of the analysis, and conclusions drawn from the results.

The small business impacts analysis for the NSPS and NESHAP amendments relies upon a series of firm-level sales tests (represented as cost-to-revenue ratios) for firms that are likely to be associated with NAICS codes listed in Table 7-15. For both the NSPS and NESHAP amendments, we obtained firm-level employment, revenues, and production levels using various sources, including the American Business Directory, the *Oil and Gas Journal*, corporate websites, and publically-available financial reports. Using these data, we estimated firm-level compliance cost impacts and calculated cost-to-revenue ratios to identify small firms that might be significantly impacts by the rules. The approaches taken for the NSPS and NESHAP amendments differed; more detail on approaches for each set of proposed rules is presented in the following sections.

For the sales test, we divided the estimates of annualized establishment compliance costs by estimates of firm revenue. This is known as the cost-to-revenue ratio, or the "sales test." The "sales test" is the impact methodology EPA employs in analyzing small entity impacts as opposed to a "profits test," in which annualized compliance costs are calculated as a share of profits. The sales test is often used because revenues or sales data are commonly available for entities impacted by EPA regulations, and profits data normally made available are often not the true profit earned by firms because of accounting and tax considerations. Revenues as typically published are correct figures and are more reliably reported when compared to profit data. The use of a "sales test" for estimating small business impacts for a rulemaking such as this one is consistent with guidance offered by EPA on compliance with SBREFA[55] and is consistent with guidance published by the U.S. SBA's Office of Advocacy that suggests that cost as a percentage

[55] The SBREFA compliance guidance to EPA rulewriters regarding the types of small business analysis that should be considered can be found at <http://www.epa.gov/sbrefa/documents/rfaguidance11-00-06.pdf>

of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities (U.S. SBA, 2010).[568]

7.4.3 Small Entity Economic Impact Analysis, Proposed NSPS

7.4.3.1 Overview of Sample Data and Methods

The proposed NSPS covers emissions points within various stages of the oil and natural gas production process. We expect that firms within multiple NAICS codes will be affected, namely the NAICS categories presented in Table 7-15. Because of the diversity of the firms potentially affected, we decided to analyze three distinct groups of firms within the oil and natural gas industry, while accounting for overlap across the groups. We analyze firms that are involved in oil and natural gas extraction that are likely to drill and operate wells, while a subset are integrated firms involved in multiple segments of production, as well as retailing products. We also analyze firms that primarily operate natural gas processing plants. A third set of firms we analyzed contains firms that primarily operate natural gas compression and pipeline transmission.

To identify firms involved in the drilling and primary production of oil and natural gas, we relied upon the annual *Oil and Gas Journal* 150 Survey (OGJ 150) as described in the Industry Profile in Section 2. While the OGJ 150 lists public firms, we believe the list is reasonably representative of the larger population of public and private firms operating in this segment of the industry. While the proportion of small firm in the OGJ 150 is smaller than the proportion evaluated by the Census SUSB, the OGJ 150 provides detailed information on the production activities and financial returns of the firms within the list, which are critical ingredients to the small business impacts analysis. We drew upon the OGJ 150 lists published for the years 2008 and 2009 (*Oil and Gas Journal*, September 21, 2009 and *Oil and Gas Journal*, September 6, 2010). The year 2009 saw relatively low levels of drilling activities because of the economic recession, while 2008 saw a relatively high level of drilling activity because of high fuel prices. Combined, we believe these two years of data are representative.

[56]U.S. SBA, Office of Advocacy. A Guide for Government Agencies, How to Comply with the Regulatory Flexibility Act, Implementing the President's Small Business Agenda and Executive Order 13272, June 2010.

To identify firms that process natural gas, the OGJ also releases a period report entitled "Worldwide Gas Processing Survey", which provides a wide range of information on existing processing facilities. We used the most recent list of U.S. gas processing facilities[57] and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. To identify firms that compress and transport natural gas via pipelines, we examined the periodic OGJ survey on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies.[58] For these firms, we also used the American Business Directory and corporate websites to best identify the ultimate owner of the facilities or companies.

After combining the information for exploration and production firms, natural gas processing firms, and natural gas pipeline transmission firms in order to identify overlaps across the list, the approach yielded a sample of 274 firms that would potentially be affected by the proposed NSPS in 2015 assuming their 2015 production activities were similar to those in 2008 and 2009. We estimate that 129 (47 percent) of these firms are small according to SBA criteria. We estimate 121 firms (44 percent) are not small firms according to SBA criteria. We are unable to classify the remaining 24 firms (9 percent) because of a lack of required information on employee counts or revenue estimates.

Table 7-18 shows the estimated revenues for 250 firms for which we have sufficient data that would be potentially affected by the proposed NSPS based upon their activities in 2008 and 2009. We segmented the sample into four groups, production and integrated firms, processing firms, pipeline firms, and pipelines/processing firms. For the firms in the pipelines/processing group, we were unable to determine the firms' primary line of business, so we opted to group together as a fourth group.

[57] Oil and Gas Journal. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010.
[58] Oil and Gas Journal. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

Table 7-18 Estimated Revenues for Firms in Sample, by Firm Type and Size

		Estimated Revenues (millions, 2008 dollars)				
Firm Type/Size	Number of Firms	Total	Average	Median	Minimum	Maximum
Production and Integrated						
Small	79	18,554.5	234.9	76.3	0.1	1,116.9
Large	49	1,347,463.0	27,499.2	1,788.3	12.9	310,586.0
Subtotal	128	1,366,017.4	10,672.0	344.6	0.1	310,586.0
Pipeline						
Small	11	694.5	63.1	4.6	0.5	367.0
Large	36	166,290.2	4,619.2	212.9	7.1	112,493.0
Subtotal	47	166,984.6	3,552.9	108.0	0.5	112,493.0
Processing						
Small	39	4,972.1	127.5	26.9	1.9	1,459.1
Large	23	177,632.1	8,881.6	2,349.4	10.4	90,000.0
Subtotal	62	182,604.2	3,095.0	41.3	1.9	90,000.0
Pipelines/Processing						
Small	0	N/A	N/A	N/A	N/A	N/A
Large	13	175,128.5	13,471.4	6,649.4	858.6	71,852.0
Subtotal	13	175,128.5	13,471.4	6,649.4	858.6	71,852.0
Total						
Small	**129**	**24,221.1**	**187.8**	**34.9**	**0.1**	**1,459.1**
Large	**121**	**1,866,513.7**	**15,817.9**	**1,672.1**	**7.1**	**310,586.0**
Total	**250**	**1,890,734.8**	**7,654.8**	**163.9**	**0.1**	**310,586.0**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. *Oil and Gas Journal*. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010, with additional analysis to determine ultimate ownership of plants. *Oil and Gas Journal*. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010. American Business Directory was used to determine number of employees.

As shown in Table 7-18, there is a wide variety of revenue levels across firm size, as well as across industry segments. The estimated revenues within the sample are concentrated on integrated firms and firms engaged in production activities (the E&P firms mentioned earlier).

The oil and natural gas industry is capital-intensive. To provide more context on the potential impacts of new regulatory requirements, Table 7-19 presents descriptive statistics for small and large integrated and production firms from the sample of firms (121 of the 128 integrated and production firms listed in the *Oil and Gas Journal*; capital and exploration expenditures for 7 firms were not reported in the *Oil and Gas Journal*).

Table 7-19 Descriptive Statistics of Capital and Exploration Expenditures, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars)

		Capital and Exploration Expenditures (millions, 2008 dollars)				
Firm Size	Number	Total	Average	Median	Minimum	Maximum
Small	76	13,478.8	177.4	67.1	0.1	2,401.9
Large	45	126,749.3	2,816.7	918.1	10.3	22,518.7
Total	**121**	**140,228.2**	**1,158.9**	**192.8**	**0.1**	**22,518.7**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. American Business Directory was used to determine number of employees.

The average 2008 and 2009 total capital and exploration expenditures for the sample of 121 firms were $140 billion in 2008 dollars). About 10 percent of this total was spent by small firms. Average capital and explorations expenditures for small firms are about 6 percent of large firms; median expenditures of small firms are about 7 percent of large firms' expenditures. For small firms, capital and exploration expenditures are high relative to revenue, which appears to hold true more generally for independent E&P firms compared to integrated major firms. This would seem to indicate the capital-intensive nature of E&P activities. As expected, this would drive up ratios comparing estimated engineering costs to revenues and capital and exploration expenditures.

Table 7-20 breaks down the estimated number of natural gas and crude oil wells drilled by the 121 firms in the sample for which the *Oil and Gas Journal* information reported well-drilling estimates. Note the fractions on the minimum and maximum statistics; the fractions reported are due to our assumptions to estimate oil and natural gas wells drilled from the total wells drilled reported by the *Oil and Gas Journal*. The OGJ150 lists new wells drilled by firm in 2008 and 2009, but the drilling counts are not specific to crude oil or natural gas wells. We

apportion the wells drilled to natural gas and crude oil wells using the distribution of well drilling in 2009 (63 percent natural gas and 37 percent oil).

Table 7-20 Descriptive Statistics of Estimated Wells Drilled, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars)

			Estimated Average Wells Natural Gas and Crude Oil Wells Drilled (2008 and 2009)				
Well Type	Firm Size	Number of Firms	Total	Average	Median	Minimum	Maximum
Natural Gas							
	Small	76	2,288.3	30.1	6.0	0.2	259.3
	Large	45	9,445.1	209.9	149.1	0.6	868.3
	Subtotal	121	11,733.4	97.0	28.3	0.2	868.3
Crude Oil							
	Small	76	1,317.1	17.3	3.5	0.1	149.2
	Large	45	5,436.3	120.8	85.8	0.4	499.7
	Subtotal	121	6,753.4	55.8	16.3	0.1	499.7
Total							
	Small	**76**	**3,605.4**	**47.4**	**9.5**	**0.0**	**408.5**
	Large	**45**	**14,881.4**	**330.7**	**234.9**	**0.0**	**1,368.0**
	Total	**121**	**18,486.8**	**152.8**	**44.6**	**0.0**	**1,368.0**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. American Business Directory was used to determine number of employees.

This table highlights the fact that many firms drill relatively few wells; the median for small firms is 6 natural gas wells compared to 149 for large firms. Later in this section, we examine whether this distribution has implications for the engineering costs estimates, as well as the estimates of expected natural product recovery from controls such as RECs.

Unlike the analysis that follows for the analysis of impacts on small business from the NESHAP amendments, we have no specific data on potentially affected facilities under the NSPS. The NSPS will apply to new and modified sources, for which data are not fully available in advance, particularly in the case of new and modified sources such as well completions and recompletions which are spatially diffuse and potentially large in number.

The engineering cost analysis estimated compliance costs in a top-down fashion, projecting the number of new sources at an annual level and multiplying these estimates by

model unit-level costs to estimate national impacts. To estimate per-firm compliance costs in this analysis, we followed a procedure similar to that of entering estimate compliance costs in NEMS on a per well basis. We first use the OGJ150-based list to estimate engineering compliance costs for integrated and production companies that may operate facilities in more than one segment of the oil and natural gas industry. We then estimate the compliance costs per crude oil and natural gas well by totaling all compliance costs estimates in the engineering cost estimates for the proposed NSPS and dividing that cost by the total number of crude oil and natural gas wells forecast as of 2015, the year of analysis. These compliance costs include the expected revenue from natural gas and condensate recovery that result from implementation of some proposed controls.

This estimation procedure yielded an estimate of crude well compliance costs of $162 per drilled well and natural gas well compliance costs of $38,719 without considering estimated revenues from product recovery and -$2,455 per drilled well with estimated revenues from product recovery included. Note that the divergence of estimated per well costs between crude oil and natural gas wells is because the proposed NSPS requirements are primary directed toward natural gas wells. Also note that the per well cost savings estimate for natural gas wells is different than the estimated cost of implementing a REC; this difference is because this estimate is picking up savings from other control options. We then estimate a single-year, firm-level compliance cost for this subset of firms by multiplying the per well cost estimates with the well count estimates.

The OGJ reports plant processing capacity in terms of MMcf/day. In the energy system impacts analysis, the NEMS model estimates a 6.5 percent increase (from 21.05 tcf in 2011 to 22.43 tcf in 2015) in domestic natural gas production from 2011 to 2015, the analysis year. On this, basis, we estimate that natural gas processing capacity for all plants in the OGJ list will increase 1.3 percent per year. This annual increment is equivalent to an increase in national gas processing capacity of 350 bcf per year. We assume that the engineering compliance costs estimates associated with processing are distributed according to the proportion of the increased national processing capacity contributed by each processing plant. These costs are estimated at $6.9 million without estimated revenues from product recovery and $2.3 million with estimated

revenues from product recovery, respectively, in 2008 dollars, or about $20/MMcf without revenues and $7/MMcf with revenues.

The OGJ report on pipeline companies has the advantage that it reports expenditures on plant additions. We assume that the firm-level proposed compression and transmission-related NSPS compliance costs are proportional to the expenditures on plant additions and that these additions reflect a representative year or this analysis. We estimate the annual compression and transmission-related NSPS compliance costs at $5.5 million without estimated revenues from product recovery and $3.7 million with estimated revenues from product recovery, respectively, in 2008 dollars.

7.4.3.2 Small Entity Impact Analysis, Proposed NSPS, Results

Summing estimated annualized engineering compliance costs across industry segment and individual firms in our sample, we estimate firms in the OGJ-based sample will face about $480 million in 2008 dollars, about 65 percent of the estimated annualized costs of the Proposed NSPS without including revenues from additional product recovery ($740 million). When including revenues from additional product recovery, the estimated compliance costs for the firms in the sample is about -$23 million, compared to engineering cost estimate of -$45 million.

Table 7-21 presents the distribution of estimated proposed NSPS compliance costs across firm size for the firms within our sample. Evident from this table, about 98 percent of the estimated engineering compliance costs accrue to the integrated and production segment of the industry, again explain by the fact that completion-related requirements contribute the bulk of the estimated engineering compliance costs (as well as estimated emissions reductions). About 17 percent of the total estimated engineering compliance costs (and about 18 percent of the costs accruing the integrated and production segment) are focused on small firms.

Table 7-21 Distribution of Estimated Proposed NSPS Compliance Costs Without Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

		Estimated Engineering Compliance Costs Without Estimated Revenues from Natural Gas Product Recovery (2008 dollars)				
Firm Type/Size	Number of Firms	Total	Mean	Median	Minimum	Maximum
Production and Integrated						
Small	79	82,293,903	1,041,695	221,467	3,210	10,054,401
Large	49	387,489,928	7,907,958	5,730,634	15,238	33,677,388
Subtotal	128	469,783,831	3,670,186	969,519	3,210	33,677,388
Pipeline						
Small	11	3,386	308	111	18	1,144
Large	36	1,486,929	41,304	3,821	37	900,696
Subtotal	47	1,490,314	31,709	2,263	18	900,696
Processing						
Small	39	476,165	12,209	1,882	188	276,343
Large	23	859,507	37,370	8,132	38	423,645
Subtotal	62	1,335,672	21,543	2,730	38	423,645
Pipelines/Processing						
Small	0	N/A	N/A	N/A	N/A	N/A
Large	13	5,431,510	417,808	147,925	2,003	2,630,236
Subtotal	13	5,431,510	417,808	147,925	2,003	2,630,236
Total						
Small	**129**	**82,773,454**	**641,655**	**49,386**	**18**	**10,054,401**
Large	**121**	**395,267,874**	**3,266,677**	**57,220**	**37**	**33,677,388**
Total	**250**	**478,041,328**	**1,912,165**	**55,888**	**18**	**33,677,388**

These distributions are similar when the revenues from expected natural gas recovery are included (Table 7-22). About 21 percent of the total savings from the proposed NSPS is expected to accrue to small firms (about 19 percent of the savings to the integrated and production segment accrue to small firms). Note also in Table 7-22 that the pipeline and processing segments (and the pipeline/processing firms) are not expected to experience net cost savings (negative costs) from the proposed NSPS.

Table 7-22 Distribution of Estimated Proposed NSPS Compliance Costs With Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

		Estimated Engineering Compliance Costs With Estimated Revenues from Natural Gas Product Recovery (millions, 2008 dollars)				
Firm Type/Size	Number of Firms	Total	Mean	Median	Minimum	Maximum
Production and Integrated						
Small	79	-5,065,551	-64,121	-13,729	-620,880	8,699
Large	49	-22,197,126	-453,003	-318,551	-2,072,384	423,760
Subtotal	128	-27,262,676	-212,990	-43,479	-2,072,384	423,760
Pipeline						
Small	11	2,303	209	76	12	779
Large	36	1,011,572	28,099	2,599	25	612,753
Subtotal	47	1,013,876	21,572	1,539	12	612,753
Processing						
Small	39	160,248	4,109	634	63	93,000
Large	23	289,258	12,576	2,737	13	142,573
Subtotal	62	449,506	7,250	919	13	142,573
Pipelines/Processing						
Small	0	---	---	---	---	---
Large	13	3,060,373	235,413	86,301	716	1,746,730
Subtotal	13	3,060,373	235,413	86,301	716	1,746,730
Total						
Small	**129**	**-4,902,999**	**-38,008**	**-2,520**	**-620,880**	**93,000**
Large	**121**	**-17,835,922**	**-147,404**	**634**	**-2,072,384**	**1,746,730**
Total	**250**	**-22,738,922**	**-90,956**	**22**	**-2,072,384**	**1,746,730**

Table 7-23 Summary of Sales Test Ratios, Without Revenues from Additional Natural Gas Product Recovery for Firms Affected by Proposed NSPS

		Descriptive Statistics for Sales Test Ratio Without Estimated Revenues from Natural Gas Product Recovery (%)			
Firm Type/Size	Number of Firms	Mean	Median	Minimum	Maximum
Production and Integrated					
Small	79	2.18%	0.49%	0.01%	50.83%
Large	49	0.41%	0.28%	<0.01%	2.83%
Subtotal	128	1.50%	0.39%	<0.01%	50.83%
Pipeline					
Small	11	<0.01%	<0.01%	<0.01%	0.01%
Large	36	0.01%	<0.01%	<0.01%	0.06%
Subtotal	47	0.01%	<0.01%	<0.01%	0.06%
Processing					
Small	39	0.05%	0.01%	<0.01%	0.33%
Large	23	0.02%	0.01%	<0.01%	0.15%
Subtotal	62	0.04%	0.01%	<0.01%	0.33%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	<0.01%	<0.01%	<0.01%	0.01%
Subtotal	13	<0.01%	<0.01%	<0.01%	0.01%
Total					
Small	**129**	**1.34%**	**0.15%**	**<0.01%**	**50.83%**
Large	**121**	**0.17%**	**0.01%**	**<0.01%**	**2.83%**
Total	**250**	**0.78%**	**0.03%**	**<0.01%**	**50.83%**

The mean cost-sales ratio for all businesses when estimated product recovery is excluded from the analysis of the sample data is 0.78 percent, with a median ratio of 0.03 percent, a minimum of less than 0.01 percent, and a maximum of over 50 percent (Table 7-23). For small firms in the sample, the mean and median cost-sales ratios are 1.34 percent and 0.15 percent, respectively, with a minimum of less than 0.01 percent and a maximum of over 50 percent (Table 7-23). Each of these statistics indicates that, when considered in the aggregate, impacts are relatively higher on small firms than large firms when the estimated revenue from additional natural gas product recovery is excluded. However, as the next table shows, the reverse is true when these revenues are included.

Table 7-24 Summary of Sales Test Ratios, With Revenues from Additional Natural Gas Product Recovery for Firms Affected by Proposed NSPS

		Descriptive Statistics for Sales Test Ratio With Estimated Revenues from Natural Gas Product Recovery (%)			
Firm Type/Size	Number of Firms	Mean	Median	Minimum	Maximum
Production and Integrated					
Small	79	-0.13%	-0.03%	-2.96%	<0.00%
Large	49	-0.02%	-0.02%	-0.17%	0.06%
Subtotal	128	-0.09%	-0.02%	-2.96%	0.06%
Pipeline					
Small	11	<0.00%	<0.01%	<0.01%	0.01%
Large	36	0.01%	<0.01%	<0.01%	0.04%
Subtotal	47	0.01%	<0.01%	<0.01%	0.04%
Processing					
Small	39	0.01%	<0.01%	<0.01%	0.05%
Large	23	<0.00%	<0.01%	<0.01%	0.05%
Subtotal	62	0.01%	<0.01%	<0.01%	0.05%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	<0.01%	<0.01%	<0.01%	0.01%
Subtotal	13	<0.01%	<0.01%	<0.01%	0.01%
Total					
Small	**129**	**-0.08%**	**-0.01%**	**-2.96%**	**0.05%**
Large	**121**	**-0.01%**	**<0.01%**	**-0.17%**	**0.06%**
Total	**250**	**-0.04%**	**<0.01%**	**-2.96%**	**0.06%**

The mean cost-sales ratio for all businesses when estimated product recovery is included is in the sample is -0.04 percent, with a median ratio of less than 0.01 percent, a minimum of -2.96 percent, and a maximum of 0.06 percent (Table 7-24). For small firms in the sample, the mean and median cost-sales ratios are -0.08 percent and -0.01 percent, respectively, with a minimum of -2.96 percent and a maximum of 0.05 percent (Table 7-24). Each of these statistics indicates that, when considered in the aggregate, impacts are small on small business when the estimated revenue from additional natural gas product recovery are included, the reverse of the conclusion found when these revenues are excluded.

Meanwhile, Table 7-25 presents the distribution of estimated cost-sales ratios for the small firms in our sample with and without including estimates of the expected natural gas product recover from implementing controls. When revenues estimates are included, all 129

firms (100 percent) have estimated cost-sales ratios less than 1 percent. While less than 1 percent, the highest cost-sales ratios for small firms in the sample experiencing impacts are largely driven by costs accruing to processing and pipeline firms. That said, the incremental costs imposed on firms that process natural gas or transport natural gas via pipelines are not estimated to create significant impacts on a cost-sales ratio basis at the firm-level.

Table 7-25 Impact Levels of Proposed NSPS on Small Firms as a Percent of Small Firms in Sample, With and Without Revenues from Additional Natural Gas Product Recovery

	Without Estimated Revenues from Natural Gas Product Recovery		With Estimated Revenues from Natural Gas Product Recovery	
Impact Level	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected
C/S Ratio less than 1%	109	84.5%	129	100.00%
C/S Ratio 1-3%	11	8.5%	0	0.00%
CS Ratio greater than 3%	9	7.0%	0	0.00%

When the estimated revenues from product recovery are not included in the analysis, 11 firms (about 9 percent) are estimated to have sales test ratios between 1 and 3 percent. Nine firms (about 7 percent) are estimated to have sales test ratios greater than 3 percent. These results noted, the exclusion of product recovery is somewhat artificial. While the mean engineering compliance costs and revenues estimates are valid, drawing on the means ignores the distribution around the mean estimates, which risks masking effects. Because of this risk, the following section offers a qualitative discussion of small entities with regard to obtaining REC services, the validity of the cost and performance of RECs for small firms, as well as offers a discussion about whether older equipment, which may be disproportionately owned and operated be smaller producers, would be affected by the proposed NSPS.

7.4.3.3 Small Entity Impact Analysis, Proposed NSPS, Additional Qualitative Discussion

3.5.3.3.1 Small Entities and Reduced Emissions Completions

Because REC requirements of the proposed NSPS are expected to contribute the large majority of engineering compliance costs, it is important to examine these requirements more closely in the context small entities. Important issues to resolve are the scale of REC costs within a drilling project, how the payment system for recovered natural gas functions, whether small entities pursue particular "niche" strategies that may influence the costs or performance in a way that makes the estimates costs and revenues invalid.

According to the most recent natural gas well cost data from EIA, the average cost of drilling and completing a producing natural gas well in 2007 was about $4.8 million (adjusted to 2008 dollars). This average includes lower cost wells that may be relatively shallow or are not hydraulically fractured. Hydraulically fractured wells in deep formations may cost up to $10 million. RECs contracted from a service provider are estimated to cost $33,200 (in 2008 dollars) or roughly 0.3%-0.7% of the typical cost of a drilling and completing a natural gas well. As this range does not include revenues expected from natural gas and hydrocarbon condensate recovery expected to offset REC implementation costs, REC costs likely represent a small increment of the overall burden of a drilling project.

To implement an REC, a service provider, which may itself be a small entity, is typically contracted to bring a set of equipment to the well pad temporarily to capture the stream that would otherwise be vented to the atmosphere. Typically, service providers are engaged in a long term drilling program in a particular basin covering multiple wells on multiple well pads. For gas captured and sold to the gathering system, Lease Automatic Custody Transfer (LACT) meters are normally read daily automatically, and sales transactions are typically settled at the end of the month. Invoices from service providers are generally delivered in 30-day increments during the well development time period, as well as at the end of the working contract for that well pad. The conclusion from the information, based on the available information, in most cases, the owner/operator incurs the REC cost within the same 30 day period that the owner/operator receives revenue as a result of the REC.

We assume small firms are performing RECs in CO and WY, as in many instances RECs are required under state regulation. In addition to State regulations, some companies are implementing RECs voluntarily such as through participation in the EPA Natural Gas STAR Program and the focus of recent press reports.

As described in more detail below, many small independent E&P companies often do not conduct any of the actual field work. These firms will typically contract the drilling, completion, testing, well design, environmental assessment, and maintenance. Therefore, we believe it is likely that small independent E&P firms will contract for RECs from service providers if required to perform RECs. An important reminder is that performing a REC is a straightforward and inexpensive extension of drilling, completion, and testing activities.

To the extent that very small firms may specialize in operating relatively few low-producing stripper wells, it is important to ask whether low-producing wells are likely candidates for re-fracturing/re-completion and, if so, whether the expected costs and revenues would be valid. These marginal gas wells are likely to be older and in conventional formations, and as such are unlikely to be good candidates for re-fracturing/completion. To the extent the marginal wells may be good candidates for re-fracturing/completion, the REC costs are valid estimates. The average REC cost is valid for RECs performed on any well, regardless of the operator size. The reason for this is that the REC service is contracted out to specialty service providers who charge daily rates for the REC equipment and workers. The cost is not related to any well characteristic.

Large operators may receive a discount for offering larger contracts which help a service provider guarantee that REC equipment will be utilized. However, we should note that the existence of a potential discount for larger contracts is based on a strong assumption; we do not have evidence to support this assumption. Since contracting REC equipment is analogous to contracting for drilling equipment, completion equipment, etc., the premium would likely be in the same range as other equipment contracted by small operators. Since the REC cost is a small portion of the overall well drilling and completion cost, the effect of any bulk discount disparity between large and small operators will be small, if in fact it does exist.

Although small operators may own the majority of marginal and stripper wells, they will make decisions based on economics just as any sized company would. For developing a new well, any sized company will expect a return on their investment meaning the potential for sufficient gas, condensate, and/or oil production to pay back their investment and generate a return that exceeds alternative investment opportunities. Therefore, small or large operators that are performing hydraulic fracture completions will experience the same distribution of REC performance. For refracturing an existing well, the well must be a good candidate to respond to the re-fracture/completion with a production increase that merits the investment in the re-fracture/completion.

Plugging and abandoning wells is complex and costly, so sustaining the productivity of wells is important for maximizing the exploitation of proven domestic resources. However, many marginal gas wells are likely to be older and in conventional formations, and as such are unlikely to be good candidates for re-fracturing/completion, which means they are likely unaffected by the proposed NSPS.

3.5.3.3.2 Age of Equipment and Proposed Regulations

Given a large fraction of domestic oil and natural gas production is produced from older and generally low productivity wells, it is important to examine whether the proposed requirements might present impediments to owners and operators of older equipment. The NSPS is a standard that applies to new or modified sources. Because of this, NSPS requirements target new or modified affected facilities or equipment, such as processing plants and compressors. While the requirements may apply to modifications of existing facilities, it is important to discuss well completion-related requirements aside from other requirements in the NSPS distinctly.

Excluding well completion requirements from the cost estimates, the non-completion NSPS requirements (related to equipment leaks at processing plants, reciprocating and centrifugal compressors, pneumatic controllers, and storage vessels) are estimated to require $27 million in annualized engineering costs. EPA also estimates that the annualized costs of these requirements will be mostly if not fully offset by revenues expected from natural gas recovery. EPA does not expect these requirements to disproportionately affect producers with older

equipment. Meanwhile, the REC and emissions combustion requirements in the proposed NSPS relate to well completion activities at new hydraulically fractured natural gas wells and existing wells which are recompleted after being fractured or re-fractured. These requirements constitute the bulk of the expected engineering compliance expenditures (about $710 million in annualized costs) and expected revenues from natural gas product recovery (about $760 million in revenues, annually).

While age of the well and equipment may be an important factor for small and large producers in determining whether it is economical to fracture or re-fracture an existing well, this equipment is unlikely to be subject to the NSPS. To comply with completion-related requirements, producers are likely to rely heavily on portable and temporary completion equipment brought to the wellpad over a short period of time (a few days to a few weeks) to capture and combust emissions that are otherwise vented. The equipment at the wellhead—newly installed in the case of new well completions or already in place and operating in the case of existing wells—is not likely to be subject to the NSPS requirement.

7.4.3.4 Small Entity Impact Analysis, Proposed NSPS, Screening Analysis Conclusion

The number of significantly impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that many affected firms are expected to receive revenues from the additional natural gas and condensate recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated. This conclusion is enhanced because the returns to reduced emissions completion activities occur without a significant time lag between implementing the control and obtaining the recovered product unlike many control options where the emissions reductions accumulate over long periods of time; the reduced emission completions and recompletions occur over a short span of time, during which the additional product recovery is also accomplished.

7.4.4 Small Entity Economic Impact Analysis, Proposed NESHAP Amendments

The proposed NESHAP amendments will affect facilities operating three types of equipment: glycol dehydrators at production facilities, glycol dehydrators at transmission and compression facilities, and storage vessels. We identified likely affected facilities in the National Emissions Inventory (NEI) and estimated the number of newly required controls of each type that would be required by the NESHAP amendments for each facility. We then used available data sources to best identify the ultimate owner of the equipment that would likely require new controls and linked facility-level compliance cost estimates to firm-level employment and revenue data. These data were then used to calculate an estimated compliance costs to revenues ratio to identify small businesses that might be significantly impacted by the NESHAP.

While we were able to identify the owners all but 14 facilities likely to be affected, we could not obtain employment and revenue levels for all of these firms. Overall, we expect about 447 facilities to be affected, and these facilities are owned by an estimated 160 firms. We were unable to obtain financial information on 42 (26 percent) of these firms due to inadequate data. In some instances, firms are private, and financial data is not available. In other instance, firms may no longer exist, since NEI data are not updated continuously. From the ownership information and compliance cost estimates from the engineering analysis, we estimated total compliance cost per firm.

Of the 118 firms for which we have financial information, we identified 62 small firms and 56 large firms that would be affected by the NESHAP amendments. Annual compliance costs for small firms are estimated at $3.0 million (18 percent of the total compliance costs), and annual compliance costs for large firms are estimated at $10.7 million (67 percent of the total compliance costs). The facilities for which we were unable to identify the ultimate owners, employment, and revenue levels would have an estimated annual compliance cost of $2.3 million (15 percent of the total). All figures are in 2008 dollars.

The average estimated annualized compliance cost for the 62 small firms identified in the dataset is $48,000, while the mean annual revenue figure for the same firms is over $120 million, or less than 1 percent for a average sales-test ratio for all 62 firms (Table 7-26). The median

sale-test ratio for these firms is smaller at 0.14 percent. Large firms are likely to see an average of $190,000 in annual compliance costs, whereas average revenue for these firms exceeds $30 billion since this set of firms includes many of the very large, integrated energy firms. For large firms, the average sales-test ratio is about 0.01 percent, and the median sales-test ratio is less than 0.01 percent (Table 7-26).

Table 7-26 Summary of Sales Test Ratios for Firms Affected by Proposed NESHAP Amendments

Firm Size	No. of Known Affected Firms	% of Total Known Affected Firms	Mean C/S Ratio	Median C/S Ratio	Min. C/S Ratio	Max. C/S Ratio
Small	62	53%	0.62%	0.14%	< 0.01%	6.2%
Large	56	47%	0.01%	< 0.01%	< 0.01%	0.4%
All	118	100%	0.34%	0.02%	< 0.01%	6.2%

Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile 10 firms (16 percent) are likely to have impacts greater than 1 percent (Table 7-27). Four of these 10 firms are likely to have impacts greater than 3 percent (Table 7-27) While these 10 firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211 (Table 7-27).

Table 7-27 Affected Small Firms as a Percent of Small Firms Nationwide, Proposed NESHAP amendments

Firm Size	Number of Small Firms Affected Nationwide	% of Small Firms Affected Nationwide	Affected Firms as a % of National Firms (6,427)
C/S Ratio less than 1%	52	83.9%	0.81%
C/S Ratio 1-3%	6	9.7%	0.09%
CS Ratio greater than 3%	4	6.5%	0.06%

Screening Analysis Conclusion: While there are significant impacts on small business, the analysis shows that a substantial number of small firms are not impacted. Based upon the analysis in this section, we presume there is no SISNOSE arising from the proposed NESHAP amendments.

7.5 References

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ORIGINAL ARTICLE

Long-Term Ozone Exposure and Mortality

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ABSTRACT

BACKGROUND

Although many studies have linked elevations in tropospheric ozone to adverse health outcomes, the effect of long-term exposure to ozone on air pollution–related mortality remains uncertain. We examined the potential contribution of exposure to ozone to the risk of death from cardiopulmonary causes and specifically to death from respiratory causes.

METHODS

Data from the study cohort of the American Cancer Society Cancer Prevention Study II were correlated with air-pollution data from 96 metropolitan statistical areas in the United States. Data were analyzed from 448,850 subjects, with 118,777 deaths in an 18-year follow-up period. Data on daily maximum ozone concentrations were obtained from April 1 to September 30 for the years 1977 through 2000. Data on concentrations of fine particulate matter (particles that are ≤2.5 μm in aerodynamic diameter [$PM_{2.5}$]) were obtained for the years 1999 and 2000. Associations between ozone concentrations and the risk of death were evaluated with the use of standard and multilevel Cox regression models.

RESULTS

In single-pollutant models, increased concentrations of either $PM_{2.5}$ or ozone were significantly associated with an increased risk of death from cardiopulmonary causes. In two-pollutant models, $PM_{2.5}$ was associated with the risk of death from cardiovascular causes, whereas ozone was associated with the risk of death from respiratory causes. The estimated relative risk of death from respiratory causes that was associated with an increment in ozone concentration of 10 ppb was 1.040 (95% confidence interval, 1.010 to 1.067). The association of ozone with the risk of death from respiratory causes was insensitive to adjustment for confounders and to the type of statistical model used.

CONCLUSIONS

In this large study, we were not able to detect an effect of ozone on the risk of death from cardiovascular causes when the concentration of $PM_{2.5}$ was taken into account. We did, however, demonstrate a significant increase in the risk of death from respiratory causes in association with an increase in ozone concentration.

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Studies conducted over the past 15 years have provided substantial evidence that long-term exposure to air pollution is a risk factor for cardiopulmonary disease and death.[1-5] Recent reviews of this literature suggest that fine particulate matter (particles that are ≤2.5 μm in aerodynamic diameter [$PM_{2.5}$]) has a primary role in these adverse health effects.[6,7] The particulate-matter component of air pollution includes complex mixtures of metals, black carbon, sulfates, nitrates, and other direct and indirect byproducts of incomplete combustion and high-temperature industrial processes.

Ozone is a single, well-defined pollutant, yet the effect of exposure to ozone on air pollution–related mortality remains inconclusive. Several studies have evaluated this issue, but they have been short-term studies,[8-10] have failed to show a statistically significant effect,[1,3] or have been based on limited mortality data.[11] Recent reviews by the Environmental Protection Agency (EPA)[12] and the National Research Council[13] have questioned the overall consistency of the available data correlating exposure to ozone and mortality. Similar conclusions about the evidence base for the long-term effects of ozone on mortality were drawn by a panel of experts in the United Kingdom.[14]

Nonetheless, previous studies have suggested that a measurable effect of ozone may exist, particularly with respect to the risk of death from cardiopulmonary causes. In one of the larger studies, ozone was significantly associated with death from cardiopulmonary causes[15] but not with death from ischemic heart disease. However, the estimated effect of ozone on the risk of death from cardiopulmonary causes in this study was attenuated when $PM_{2.5}$ was added to the analysis in copollutant models. On the basis of suggested effects of ozone on the risk of death from cardiopulmonary causes (which includes death from respiratory causes) but an absence of evidence for effects of ozone on the risk of death from ischemic heart disease, we hypothesized that ozone might have a primary effect on the risk of death from respiratory causes.

METHODS

HEALTH, MORTALITY, AND CONFOUNDING DATA

Our study used data from the American Cancer Society Cancer Prevention Study II (CPS II) cohort.[16] The CPS II cohort consists of more than 1.2 million participants who were enrolled by American Cancer Society volunteers between September 1982 and February 1983 in all 50 states, the District of Columbia, and Puerto Rico. Enrollment was restricted to persons who were at least 30 years of age living in households with at least one person 45 years of age or older. After providing written informed consent, the participants completed a confidential questionnaire that included questions on demographic characteristics, smoking history, alcohol use, diet, and education.[17] Deaths were ascertained until August 1988 by personal inquiries of family members by the volunteers and thereafter by linkage with the National Death Index. Through 1995, death certificates were obtained and coded for cause of death. Beginning in 1996, codes for cause of death were provided by the National Death Index.[18]

The study population for our analysis included only those participants in CPS II who resided in U.S. metropolitan statistical areas within the 48 contiguous states or the District of Columbia (according to their address at the time of enrollment) and for whom data were available from at least one pollution monitor within their metropolitan area. The study was approved by the Ottawa Hospital Research Ethics Board, Canada.

Data on "ecologic" risk factors at the level of the metropolitan area representing social variables (educational level, percentage of homes with air conditioning, percentage of the population who were nonwhite), economic variables (household income, unemployment, income disparity), access to medical care (number of physicians and hospital beds per capita), and meteorologic variables were obtained from the 1980 U.S. Census and other secondary sources (see the Supplementary Appendix, available with the full text of this article at NEJM.org). These ecologic risk factors, as well as the individual risk factors collected in the CPS II questionnaire, were assessed as potential confounders of the effects of ozone.[3,5,19,20]

ESTIMATES OF EXPOSURE TO AIR POLLUTION

Ozone data were obtained from 1977 (5 years before the identification of the CPS II cohort) through 2000 for all air-pollution monitors in the study metropolitan areas from the EPA's Aerometric Information Retrieval System. Ozone data at each monitoring site were collected on an hourly basis, and the daily maximum value for the site was determined. All available daily maximum values for the monitoring site were averaged over

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each quarter year. The quarterly average values were reported for each monitor only when at least 75% of daily observations for that quarter were available.

The averages of the second (April through June) and third (July through September) quarters were calculated for each monitor if both quarterly averages were available. The period from April through September was selected because ozone concentrations tend to be elevated during the warmer seasons and because fewer data were available for the cooler seasons.

The average of the second and third quarterly averages for each year was then computed for all the monitors within each metropolitan area to form a single annual time series of air-pollution measurements for each metropolitan area for the period from 1977 to 2000. In addition, a summary measure of long-term exposure to ambient warm-season ozone was defined as the average of annual time-series measurements during the entire period from 1977 to 2000. Individual measures of exposure to ozone were then defined by assigning the average for the metropolitan area to each cohort member residing in that area.

Data on exposure to $PM_{2.5}$ were also obtained from the Aerometric Information Retrieval System database for the 2-year period from 1999 to 2000 (data on $PM_{2.5}$ were not available before 1999 for most metropolitan areas).[5] The average concentrations of $PM_{2.5}$ were included in our analyses to distinguish the effect of particulates from that of ozone on outcomes.

STATISTICAL ANALYSIS

Standard and multilevel random-effects Cox proportional-hazard models were used to assess the risk of death in relation to exposures to pollution. The subjects were matched according to age (in years), sex, and race. A total of 20 variables with 44 terms were used to control for individual characteristics that might confound or modify the association between air pollution and death. These variables, which were considered to be of potential importance on the basis of previous studies, included individual risk factors for which data had been collected in the CPS II questionnaire. Seven ecologic covariates obtained from the 1980 U.S. Census (median household income, the proportion of persons living in households with an income below 125% of the poverty line, the percentage of persons over the age of 16 years who were unemployed, the percentage of adults with less than a high-school [12th-grade] education, the percentage of homes with air conditioning, the Gini coefficient of income inequality [ranging from 0 to 1, with 0 indicating an equal distribution of income and 1 indicating that one person has all the income and everyone else has no income[20]], and the percentage of persons who were white) were also included. These variables were included at two levels: as the average for the metropolitan statistical area and as the difference between the average for the ZIP Code of residence and the average for the metropolitan statistical area. Additional sensitivity analyses were undertaken for ecologic variables that were available for only a subgroup of the 96 metropolitan statistical areas (see the Supplementary Appendix). Models were estimated for either ozone or $PM_{2.5}$. In addition, models with both $PM_{2.5}$ and ozone were estimated.

In additional analyses, our basic Cox models were modified by incorporating an adjustment for community-level random effects, which allowed us to take into account residual variation in mortality among communities.[21] The baseline hazard function was modulated by a community-specific random variable representing the residual risk of death for subjects in that community after individual and ecologic risk factors had been controlled for (see the Supplementary Appendix).

A formal analysis was conducted to assess whether a threshold existed for the association between exposure to ozone and the risk of death (see the Supplementary Appendix). A standard threshold model was postulated in which there was no association between exposure to ozone and the risk of death below a specified threshold concentration and a linear association (on the logarithmic scale of the proportional-hazards model) above the threshold.

The question of whether specific time windows were associated with the health effects was investigated by subdividing the follow-up interval into four periods (1982 to 1988, 1989 to 1992, 1993 to 1996, and 1997 to 2000). Exposures were matched for each of these periods and also tested for a 10-year average on the basis of the 5-year follow-up period and the 5 years before the follow-up period (see the Supplementary Appendix).

RESULTS

The analytic cohort included 448,850 subjects residing in 96 metropolitan statistical areas (Fig. 1).

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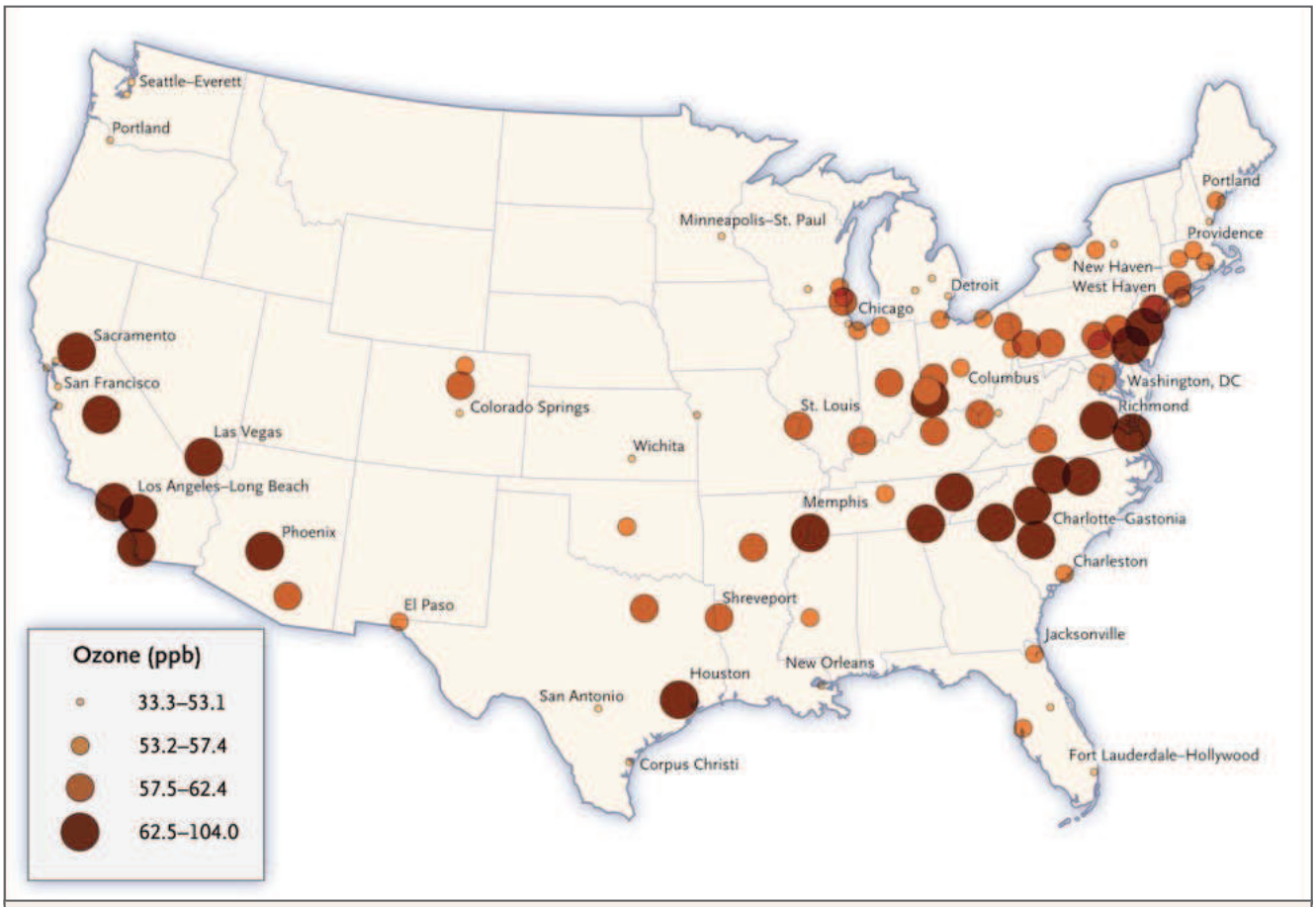


Figure 1. Ozone Concentrations in the 96 Metropolitan Statistical Areas in Which Members of the American Cancer Society Cohort Resided in 1982.

The average exposures were estimated from 1 to 57 monitoring sites within each metropolitan area from April 1 to September 30 for the years 1977 through 2000.

In 1980, the populations of these 96 areas ranged from 94,436 to 8,295,900. Data were available on the concentration of ambient ozone from all 96 areas and on the concentration of $PM_{2.5}$ from 86 areas. The average number of air-pollution monitors per metropolitan area was 11 (range, 1 to 57), and more than 80% of the areas had 6 or more monitors.

The average ozone concentration for each metropolitan area during the interval from 1977 to 2000 ranged from 33.3 ppb to 104.0 ppb (Fig. 1). The highest regional concentrations were in Southern California and the lowest in the Pacific Northwest and parts of the Great Plains. Moderately elevated concentrations were present in many areas of the East, Midwest, South, and Southwest.

The baseline characteristics of the study population, overall and as a function of exposure to ozone, are presented in Table 1. The mean age of the cohort was 56.6 years, 43.4% were men, 93.7% were white, 22.4% were current smokers, and 30.5% were former smokers. On the basis of estimates from 1980 Census data, 62.3% of homes had air conditioning at the time of initial data collection.

During the 18-year follow-up period (from initial CPS II data collection in 1982 through the end of follow-up in 2000), there were 118,777 deaths in the study cohort (Table 2). Of these, 58,775 were from cardiopulmonary causes, including 48,884 from cardiovascular causes (of which 27,642 were due to ischemic heart disease) and 9891 from respiratory causes.

In the single-pollutant models, exposure to ozone was not associated with the overall risk of death (relative risk, 1.001; 95% confidence interval [CI], 0.996 to 1.007) (Table 3). However, it was significantly correlated with an increase in the risk of death from cardiopulmonary causes. A

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10-ppb increment in exposure to ozone elevated the relative risk of death from the following causes: cardiopulmonary causes (relative risk, 1.014; 95% CI, 1.007 to 1.022), cardiovascular causes (relative risk, 1.011; 95% CI, 1.003 to 1.023), ischemic heart disease (relative risk, 1.015; 95% CI, 1.003 to 1.026), and respiratory causes (relative risk, 1.029; 95% CI, 1.010 to 1.048).

Inclusion of the concentration of $PM_{2.5}$ measured in 1999 and 2000 as a copollutant (Table 3) attenuated the association with exposure to ozone for all the end points except death from respiratory causes, for which a significant correlation persisted (relative risk, 1.040; 95% CI, 1.013 to 1.067). The concentrations of ozone and $PM_{2.5}$ were positively correlated (r=0.64 at the subject level and r=0.56 at the metropolitan-area level), resulting in unstable risk estimates for both pollutants. The concentration of $PM_{2.5}$ remained significantly associated with death from cardio-

Table 1. Baseline Characteristics of the Study Population in the Entire Cohort and According to Exposure to Ozone.*

Variable	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
No. of MSAs	96	24	24	24	24
No. of MSAs with data on $PM_{2.5}$	86	21	20	23	22
Concentration of $PM_{2.5}$ ($\mu g/m^3$)		11.9±2.5	13.1±2.9	14.7±2.1	15.4±3.2
Individual risk factors					
Age (yr)	56.6±10.5	56.7±10.4	56.4±10.7	56.3±10.4	56.9±10.5
Male sex (%)	43.4	43.5	43.1	43.5	43.2
White race (%)	93.7	94.3	95.1	93.9	91.8
Education (%)					
Less than high school	12.1	11.5	13.6	12.1	11.6
High school	30.6	30.2	33.6	32.1	27.4
Beyond high school	57.3	58.3	52.8	55.8	61.0
Smoking status					
Current smokers					
Percentage of subjects	22.4	22.0	23.5	22.2	21.9
No. of cigarettes/day	22.0±12.4	22.0±12.3	22.0±12.5	22.2±12.5	21.9±12.4
Duration of smoking (yr)	33.5±11.0	33.4±10.8	33.4±11.1	33.4±11.0	33.9±11.2
Started smoking <18 yr of age (%)	9.6	9.3	10.5	9.4	9.3
Started smoking ≥18 yr of age (%)	13.2	13.3	13.4	13.3	13.0
Former smokers					
Percentage of subjects	30.5	31.2	30.8	29.5	30.4
No. of cigarettes/day	21.6±14.7	21.6±14.6	22.2±15.1	21.6±14.6	21.3±14.6
Duration of smoking (yr)	22.2±12.6	22.1±12.5	22.6±12.6	22.0±12.5	22.4±12.7
Started smoking <18 yr of age (%)	11.9	11.8	12.7	11.5	11.8
Started smoking ≥18 yr of age (%)	18.5	19.3	17.9	17.9	18.5
Exposure to smoking (hr/day)	3.3±4.4	3.2±4.4	3.4±4.5	3.4±4.5	3.1±4.4
Pipe or cigar smoker only (%)	4.1	4.0	4.2	4.3	3.8
Marital status (%)					
Married	83.5	84.2	83.0	83.7	83.1
Single	3.6	3.4	4.0	3.8	3.2
Separated, divorced, or widowed	12.9	12.4	13.0	12.5	13.7

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Table 1. (Continued.)

Variable	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
Body-mass index†	25.1±4.1	25.1±4.1	25.3±4.2	25.1±4.1	24.8±4.0
Level of occupational exposure to particulate matter (%)‡					
0	50.7	50.9	50.0	50.8	51.0
1	13.3	13.4	13.1	13.3	13.3
2	11.4	11.5	10.8	11.4	11.9
3	4.6	4.7	4.8	4.6	4.5
4	6.1	6.2	6.2	6.1	6.0
5	4.2	4.2	4.3	4.1	4.1
6	1.1	1.0	9.5	1.4	8.4
Not able to ascertain	8.6	8.2	1.2	8.4	0.9
Self-reported exposure to dust or fumes (%)	19.5	19.5	19.8	19.7	19.1
Level of dietary-fat consumption (%)§					
0	14.5	13.7	14.9	14.1	15.3
1	15.9	15.8	16.5	15.6	15.9
2	17.4	17.6	17.7	17.2	17.1
3	21.2	21.8	21.1	21.3	20.8
4	30.9	31.1	29.8	31.9	30.9
Level of dietary-fiber consumption (%)¶					
0	16.6	16.0	17.5	16.7	16.6
1	19.9	19.4	20.5	20.1	19.7
2	18.8	18.6	19.2	19.1	18.5
3	22.8	23.0	22.4	22.8	22.7
4	21.9	23.0	20.4	21.3	22.5
Alcohol consumption (%)					
Beer					
Drinks beer	22.9	24.3	23.2	22.9	21.4
Does not drink beer	9.7	9.5	9.3	9.5	10.2
No data	67.4	66.2	67.5	67.6	68.4
Liquor					
Drinks liquor	28.0	30.4	27.9	25.4	27.9
Does not drink liquor	8.8	8.4	8.5	10.1	9.2
No data	63.2	61.2	63.6	65.5	62.9
Wine					
Drinks wine	23.5	25.4	22.5	21.1	24.3
Does not drink wine	8.9	8.7	8.8	9.3	9.1
No data	67.6	65.9	68.7	69.6	66.6

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Table 1. (Continued.)

Variable	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
Ecologic risk factors‖					
Nonwhite race (%)	11.6±16.8	10.5±16.4	9.3±15.5	10.2±16.0	15.9±18.3
Home with air conditioning (%)	62.3±27.0	55.4±31.2	59.4±24.0	65.3±24.8	69.1±24.3
High-school education or greater (%)	51.7±8.2	53.5±7.9	52.4±7.5	50.8±7.2	50.0±9.5
Unemployment rate (%)	11.7±3.1	12.1±3.4	11.3±2.6	11.3±2.9	11.8±3.4
Gini coefficient of income inequality**	0.37±0.04	0.37±0.05	0.37±0.04	0.37±0.04	0.38±0.04
Proportion of population with income <125% of poverty line	0.12±0.08	0.11±0.08	0.12±0.08	0.11±0.07	0.13±0.09
Annual household income (thousands of dollars)††	20.7±6.6	21.9±7.1	19.8±6.0	21.2±6.7	19.7±6.3

* MSA denotes metropolitan statistical area, and $PM_{2.5}$ fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Plus–minus values are means ±SD. Because of rounding, percentages may not total 100. All baseline characteristics included in the survival model are listed (age, sex, and race were included as stratification factors). The model also includes squared terms for the number of cigarettes smoked per day and the number of years of smoking for both current and former smokers and a squared term for body-mass index.

† The body-mass index is the weight in kilograms divided by the square of the height in meters.

‡ Occupational exposure to particulate matter increases with increasing index number. The index was calculated by assigning a relative level of exposure to $PM_{2.5}$ associated with a cohort member's job and industry. These assignments were performed by industrial hygienists on the basis of their knowledge of typical exposure patterns for each occupation and specific job.[22]

§ Dietary-fat consumption increases with increasing index number. Dietary information from cohort members was used to define the level of fat consumption according to five ordered categories.[20]

¶ Dietary-fiber consumption increases with increasing index number. Dietary information from cohort members was used to define the level of fiber consumption according to five ordered categories.[23]

‖ For the ecologic variables, the model included terms for influences at the level of the average for the metropolitan statistical area and at the level of the difference between the value for the ZIP Code of residence and the average for the metropolitan statistical area to represent between- and within-metropolitan area confounding influence. Some values for ecologic variables and individual variables differ, although they appear to measure the same risk factor. For example, for the entire cohort, the percentage of whites as listed under individual variables is 93.7, whereas the percentage of nonwhites as listed under ecologic variables is 11.6±16.8. This apparent contradiction is explained by the fact that the former is an exact figure based on the individual reports of the study participants in the CPS II questionnaire, whereas the latter is a mean (±SD) for the population based on Census estimates for each metropolitan statistical area.

** The Gini coefficient is a statistical dispersion measure used to calculate income inequality. The coefficient ranges from 0 to 1, with 0 indicating an equal distribution of income and 1 indicating that one person has all the income and everyone else has no income.[20] A coefficient of 0.37 indicates that on average there is a measurable inequality in the distribution of income among the different income groups within the MSAs.

†† Average household incomes for the cohort and for each quartile of ozone concentration were calculated from the median household income for the metropolitan statistical area.

pulmonary causes, cardiovascular causes, and ischemic heart disease when ozone was included in the model. The association of ozone concentrations with death from respiratory causes remained significant after adjustment for $PM_{2.5}$.

Risk estimates for ozone-related death from respiratory causes were insensitive to the use of a random-effects survival model allowing for spatial clustering within the metropolitan area and state of residence (Table 1S in the Supplementary Appendix). The association between increased ozone concentrations and increased risk of death from respiratory causes was also insensitive to adjustment for several ecologic variables considered individually (Table 2S in the Supplementary Appendix).

Subgroup analyses showed that environmental temperature and region of the country, but not sex, age at enrollment, body-mass index, education, or concentration of $PM_{2.5}$, significantly modified the effects of ozone on the risk of death from respiratory causes (Table 4).

Figure 2 illustrates the shape of the relation between exposure to ozone and death from re-

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Table 2. Number of Deaths in the Entire Cohort and According to Exposure to Ozone.

Cause of Death	Entire Cohort (N=448,850)	Concentration of Ozone			
		33.3–53.1 ppb (N=126,206)	53.2–57.4 ppb (N=95,740)	57.5–62.4 ppb (N=106,545)	62.5–104.0 ppb (N=120,359)
		number of deaths			
Any cause	118,777	32,957	25,642	27,782	32,396
Cardiopulmonary	58,775	16,328	12,621	13,544	16,282
Cardiovascular	48,884	13,605	10,657	11,280	13,342
Ischemic heart disease	27,642	7,714	6,384	6,276	7,268
Respiratory	9,891	2,723	1,964	2,264	2,940

Table 3. Relative Risk of Death Attributable to a 10-ppb Change in the Ambient Ozone Concentration.*

Cause of Death	Single-Pollutant Model†			Two-Pollutant Model‡	
	Ozone (96 MSAs)	Ozone (86 MSAs)	$PM_{2.5}$ (86 MSAs)	Ozone (86 MSAs)	$PM_{2.5}$ (86 MSAs)
			relative risk (95% CI)		
Any cause	1.001 (0.996–1.007)	1.001 (0.996–1.007)	1.048 (1.024–1.071)	0.989 (0.981–0.996)	1.080 (1.048–1.113)
Cardiopulmonary	1.014 (1.007–1.022)	1.016 (1.008–1.024)	1.129 (1.094–1.071)	0.992 (0.982–1.003)	1.153 (1.104–1.204)
Respiratory	1.029 (1.010–1.048)	1.027 (1.007–1.046)	1.031 (0.955–1.113)	1.040 (1.013–1.067)	0.927 (0.836–1.029)
Cardiovascular	1.011 (1.003–1.023)	1.014 (1.005–1.023)	1.150 (1.111–1.191)	0.983 (0.971–0.994)	1.206 (1.150–1.264)
Ischemic heart disease	1.015 (1.003–1.026)	1.017 (1.006–1.029)	1.211 (1.156–1.268)	0.973 (0.958–0.988)	1.306 (1.226–1.390)

* MSA denotes metropolitan statistical area, and $PM_{2.5}$ fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Ozone concentrations were measured from April to September during the years from 1977 to 2000, with follow-up from 1982 to 2000; changes in the concentration of $PM_{2.5}$ of 10 μg per cubic meter were recorded for members of the cohort in 1999 and 2000. These models are adjusted for all the individual and ecologic risk factors listed in Table 1. For the ecologic variables, the model included terms for influences at the level of the average for the metropolitan statistical area and at the level of the difference between the value for the ZIP Code of residence and the average for the metropolitan statistical area to represent between- and within-metropolitan area confounding influence. The risk of death was stratified according to age (in years), sex, and race.

† The single-pollutant models were based on 96 metropolitan statistical areas for which information on ozone was available and 86 metropolitan statistical areas for which information on both ozone and fine particulate matter was available.

‡ The two-pollutant models were based on 86 metropolitan statistical areas for which information on both ozone and fine particulate matter was available.

spiratory causes. There was limited evidence that a threshold model specification improved model fit as compared with a nonthreshold linear model (P=0.06) (Table 3S in the Supplementary Appendix).

Because air-pollution data from 1977 to 2000 were averaged, exposure values for persons who died during this period are based partly on data that were obtained after death had occurred. Further investigation by dividing this interval into specific time windows of exposure revealed no significant difference between the effects of earlier and later time windows within the period of follow-up. Allowing for a 10-year period of exposure to ozone (5 years of follow-up and 5 years before the follow-up period) did not appreciably alter the risk estimates (Table 4S in the Supplementary Appendix). Thus, when exposure values were matched more closely to the follow-up period and when exposure values were based on data obtained before the deaths, there was little change in the results.

DISCUSSION

Our principal finding is that ozone and $PM_{2.5}$ contributed independently to increased annual mortality rates in this large, U.S. cohort study in analyses that controlled for many individual and ecologic risk factors. In two-pollutant models that

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included ozone and $PM_{2.5}$, ozone was significantly associated only with death from respiratory causes.

For every 10-ppb increase in exposure to ozone, we observed an increase in the risk of death from respiratory causes of about 2.9% in single-pollutant models and 4% in two-pollutant models. Although this increase may appear moderate, the risk of dying from a respiratory cause is more than three times as great in the metropolitan areas with the highest ozone concentrations as in those with the lowest ozone concentrations. The effects of ozone on the risk of death from respiratory causes were insensitive to adjustment for individual, neighborhood, and metropolitan-area confounders or to differences in multilevel-model specifications.

There is biologic plausibility for a respiratory effect of ozone. In laboratory studies, ozone can increase airway inflammation[24] and can worsen pulmonary function and gas exchange.[25] In addition, exposure to elevated concentrations of tropospheric ozone has been associated with numerous adverse health effects, including the induction[26] and exacerbation[27,28] of asthma, pulmonary dysfunction,[29,30] and hospitalization for respiratory causes.[31]

Despite these observations, previous studies linking long-term exposure to ozone with death have been inconclusive. One cohort study conducted in the Midwest and eastern United States reported an inverse but nonsignificant association between ozone concentrations and mortality.[1] Subsequent reanalyses of this study replicated these findings but also suggested a positive association with exposure to ozone during warm seasons.[3] A study of approximately 6000 nonsmoking Seventh-Day Adventists living in Southern California showed elevated risks among men after long-term exposure to ozone,[11] but this finding was based on limited mortality data.

Previous studies using the CPS II cohort have also produced mixed results for ozone. An earlier examination based on a large sample of more than 500,000 people from 117 metropolitan areas and 8 years of follow-up indicated nonsignificant results for the relation between ozone and death from any cause and a significant inverse association between ozone and death from lung cancer. A positive association between death from cardiopulmonary causes and summertime exposure to ozone was observed in single-pollutant

Table 4. Relative Risk of Death from Respiratory Causes Attributable to a 10-ppb Change in the Ambient Ozone Concentration, Stratified According to Selected Risk Factors.*

Stratification Variable	% of Subjects in Stratum	Relative Risk (95% CI)	P Value of Effect Modification
Sex			0.11
Male	43	1.01 (0.99–1.04)	
Female	57	1.04 (1.03–1.07)	
Age at enrollment (yr)			0.74
<50	26	1.00 (0.90–1.11)	
50–65	54	1.03 (1.01–1.06)	
>65	20	1.02 (1.00–1.05)	
Education			0.48
High school or less	43	1.02 (1.00–1.05)	
Beyond high school	57	1.03 (1.01–1.06)	
Body-mass index†			0.96
<25.0	53	1.03 (1.01–1.06)	
25.0–29.9	36	1.03 (0.99–1.06)	
≥30.0	11	1.03 (0.96–1.10)	
$PM_{2.5}$ ($\mu g/m^3$)‡			0.38
<14.3	44	1.05 (1.01–1.09)	
>14.3	56	1.03 (1.00–1.05)	
Region§			0.05
Northeast	24.8	0.99 (0.92–1.07)	
Industrial Midwest	29.7	1.00 (0.91–1.09)	
Southeast	21.0	1.12 (1.05–1.19)	
Upper Midwest	5.2	1.14 (0.68–1.90)	
Northwest	7.7	1.06 (1.00–1.13)	
Southwest	3.9	1.21 (1.04–1.40)	
Southern California	7.8	1.01 (0.96–1.07)	
External temperature (°C)‡¶			0.01
<23.3	24	0.96 (0.90–1.01)	
>23.3 to <25.4	29	0.97 (0.87–1.08)	
>25.4 to <28.7	22	1.04 (0.92–1.16)	
>28.7	25	1.05 (1.03–1.08)	

* $PM_{2.5}$ denotes fine particulate matter consisting of particles that are 2.5 μm or less in aerodynamic diameter. Ozone exposures for the cohort were measured from April to September during the years from 1977 to 2000, with follow-up from 1982 to 2000, with adjustment for individual risk factors, and with baseline hazard function stratified according to age (single-year groupings), sex, and race. These analyses are based on the single-pollutant model for ozone shown in Table 3. Because of rounding, percentages may not total 100.
† The body-mass index is the weight in kilograms divided by the square of the height in meters.
‡ Stratum cutoff is based on the median of the distribution at the metropolitan-area level, not at the subject level.
§ Definitions of regions are those used by the Environmental Protection Agency.[3]
¶ External temperature is calculated as the average daily maximum temperature recorded between April and September from 1977 to 2000.

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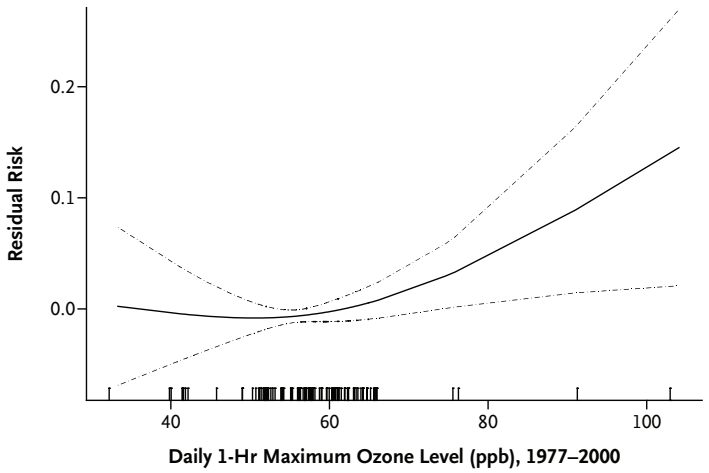


Figure 2. Exposure–Response Curve for the Relation between Exposure to Ozone and the Risk of Death from Respiratory Causes.

The curve is based on a natural spline with 2 df estimated from the residual relative risk of death within a metropolitan statistical area (MSA) according to a random-effects survival model. The dashed lines indicate the 95% confidence interval of fit, and the hash marks indicate the ozone levels of each of the 96 MSAs.

models, but the association with ozone was nonsignificant in two-pollutant models.[3] Further analyses based on 16 years of follow-up in 134 cities produced similarly elevated but nonsignificant associations that were suggestive of effects of summertime (July to September) exposure to ozone on death from cardiopulmonary causes.[5]

The increase in deaths from respiratory causes with increasing exposure to ozone may represent a combination of short-term effects of ozone on susceptible subjects who have influenza or pneumonia and long-term effects on the respiratory system caused by airway inflammation,[24] with subsequent loss of lung function in childhood,[32] young adulthood,[33,34] and possibly later life.[35] If exposure to ozone accelerates the natural loss of adult lung function with age, those exposed to higher concentrations of ozone would be at greater risk of dying from a respiratory-related syndrome.

In our two-pollutant models, the adjusted estimates of relative risk for the effect of ozone on the risk of death from cardiovascular causes were significantly less than 1.0, seemingly suggesting a protective effect. Such a beneficial influence of ozone, however, is unlikely from a biologic standpoint. The association of ozone with cardiovascular end points was sensitive to adjustment for exposure to $PM_{2.5}$, making it difficult to determine precisely the independent contributions of these copollutants to the risk of death. There was notable collinearity between the concentrations of ozone and $PM_{2.5}$.

Furthermore, measurement at central monitors probably represents population exposure to $PM_{2.5}$ more accurately than it represents exposure to ozone. Ozone concentration tends to vary spatially within cities more than does $PM_{2.5}$ concentration, because of scavenging of ozone by nitrogen oxide near roadways.[36] In the presence of a high density of local traffic, the measurement error is probably higher for exposure to ozone than for exposure to $PM_{2.5}$. The effects of ozone could therefore be confounded by the presence of $PM_{2.5}$ because of collinearity between the measurements of the two pollutants and the higher precision of measurements of $PM_{2.5}$.[37]

Measurements of $PM_{2.5}$ were available only for the end of the study follow-up period (1999 and 2000). Widespread collection of these data began only after the EPA adopted regulatory limits on such particulates in 1997. Since particulate air pollution has probably decreased in most metropolitan areas during the follow-up interval of our study, it is likely that we have underestimated the effect of $PM_{2.5}$ in our analysis.

A limitation of our study is that we were not able to account for the geographic mobility of the population during the follow-up period. We had information on home addresses for the CPS II cohort only at the time of initial enrollment in 1982 and 1983. Census data indicate that during the interval between 1982 and 2000, approximately 2 to 3% of the population moved from one state to another annually (with the highest rates in an age group younger than that of our study population).[38] However, any bias due to a failure to account for geographic mobility is likely to have attenuated, rather than exaggerated, the effects of ozone on mortality.

In summary, we investigated the effect of tropospheric ozone on the risk of death from any cause and cause-specific death in a large cohort, using data from 96 metropolitan statistical areas across the United States and controlling for the effect of particulate air pollutants. We were unable to detect a significant effect of exposure to ozone on the risk of death from cardiovascular causes when particulates were taken into account, but we did demonstrate a significant effect of exposure to ozone on the risk of death from respiratory causes.

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EPA United States Environmental Protection Agency

Ground-level Ozone
Health Effects

Ozone in the air we breathe can harm our health—typically on hot, sunny days when ozone can reach unhealthy levels. Even relatively low levels of ozone can cause health effects. People with lung disease, children, older adults, and people who are active outdoors may be particularly sensitive to ozone.

Children are at greatest risk from exposure to ozone because their lungs are still developing and they are more likely to be active outdoors when ozone levels are high, which increases their exposure. Children are also more likely than adults to have asthma.

Breathing ozone can trigger a variety of health problems including chest pain, coughing, throat irritation, and congestion. It can worsen bronchitis, emphysema, and asthma. Ground level ozone also can reduce lung function and inflame the linings of the lungs. Repeated exposure may permanently scar lung tissue.

Ozone can:

- Make it more difficult to breathe deeply and vigorously.
- Cause shortness of breath and pain when taking a deep breath.
- Cause coughing and sore or scratchy throat.
- Inflame and damage the airways.
- Aggravate lung diseases such as asthma, emphysema, and chronic bronchitis.
- Increase the frequency of asthma attacks.
- Make the lungs more susceptible to infection.
- Continue to damage the lungs even when the symptoms have disappeared.

These effects may lead to increased school absences, medication use, visits to doctors and emergency rooms, and hospital admissions. Research also indicates that ozone exposure may increase the risk of premature death from heart or lung disease.

Ozone is particularly likely to reach unhealthy levels on hot sunny days in urban environments. It is a major part of urban smog. Ozone can also be transported long distances by wind. For this reason, even rural areas can experience high ozone levels. And, in some cases, ozone can occur throughout the year in some southern and mountain regions. Learn more about the formation and transport of ground level ozone.

The AIRNow Web site provides daily air quality reports for many areas. These reports use the Air Quality Index (or AQI) to tell you how clean or polluted the air is. EnviroFlash, a free service, can alert you via email when your local air quality is a concern. Sign up at www.enviroflash.info.

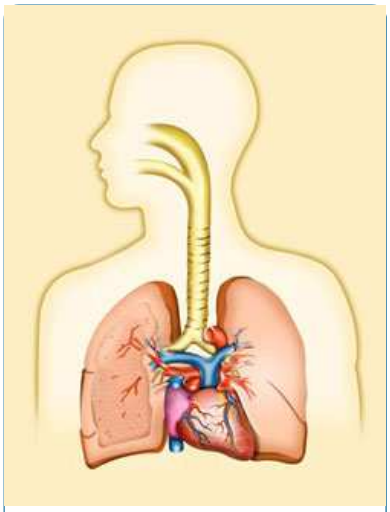
If you're a health care provider, visit AIRNow's Health Care Provider page for educational materials and trainings.

For more information on how EPA works to reduce ground level ozone, visit the Ozone Standards page.

For more information on ground level ozone, health and the environment, visit:

- Ozone and Your Health (PDF) (2 pp, 2.5 MB) This short, colorful pamphlet tells who is at risk from exposure to ozone, what health effects are caused by ozone, and simple measures that can be taken to reduce health risk.
- Ozone: Good Up High, Bad Nearby (PDF) (2 pp, 1.3 MB) Ozone acts as a protective layer high above the earth, but it can be harmful to breathe. This publication provides basic information about ground level and high-altitude ozone.
- EPA's Air Quality Guide for Ozone Provides detailed information about what the Air Quality Index means. Helps determine ways to protect your family's health when ozone levels reach the unhealthy range, and ways you can help reduce ozone air pollution.
- Ozone and Your Patients' Health Training for Health Care Providers Designed for family practice doctors, pediatricians, nurse practitioners,

What are the effects of ozone?



Effects on the Airways. Ozone is a powerful oxidant that can irritate the air ways causing coughing, a burning sensation, wheezing and shortness of breath and it can aggravate asthma and other lung diseases.



Alveoli filled with trapped air. Ozone can cause the muscles in the airways to constrict, trapping air in the alveoli. This leads to wheezing and shortness of breath. In people with asthma it can result in asthma attacks.



asthma educators, and other medical professionals who counsel patients about asthma and respiratory symptoms.

- AIRNow Health Providers Information Provides information on how to help patients protect their health by reducing their exposure to air pollution.
- EPA's Asthma Web Site EPA's Communities in Action Asthma Initiative is a coordinated effort to reduce the burden of asthma and includes programs to address indoor and outdoor environments that cause, trigger or exacerbate asthma symptoms.
- Smog - Who Does it Hurt? (PDF) (10 pp, 819 KB) This 8-page booklet provides more detailed information than "Ozone and Your Health" about ozone health effects and how to avoid them.
- Summertime Safety: Keeping Kids Safe from Sun and Smog (PDF) (2 pp, 314 KB) This document discusses summer health hazards that pertain particularly to children and includes information about EPA's Air Quality Index and UV Index tools.



Airway Inflammation. With airway inflammation, there is an influx of white blood cells, increased mucous production, and fluid accumulation and retention. This causes the death and shedding of cells that line the airways and has been compared to the skin inflammation caused by sunburn.



Ozone and Your Patients' Health Training for Health Care Providers

Last updated on Thursday, November 01, 2012

EPA United States Environmental Protection Agency

Nitrogen Dioxide
Health

Current scientific evidence links short-term NO_2 exposures, ranging from 30 minutes to 24 hours, with adverse respiratory effects including airway inflammation in healthy people and increased respiratory symptoms in people with asthma.

Also, studies show a connection between breathing elevated short-term NO_2 concentrations, and increased visits to emergency departments and hospital admissions for respiratory issues, especially asthma.

NO_2 concentrations in vehicles and near roadways are appreciably higher than those measured at monitors in the current network. In fact, in-vehicle concentrations can be 2-3 times higher than measured at nearby area-wide monitors. Near-roadway (within about 50 meters) concentrations of NO_2 have been measured to be approximately 30 to 100% higher than concentrations away from roadways.

Individuals who spend time on or near major roadways can experience short-term NO_2 exposures considerably higher than measured by the current network. Approximately 16% of U.S housing units are located within 300 ft of a major highway, railroad, or airport (approximately 48 million people). This population likely includes a higher proportion of non-white and economically-disadvantaged people.

NO_2 exposure concentrations near roadways are of particular concern for susceptible individuals, including people with asthma asthmatics, children, and the elderly

The sum of nitric oxide (NO) and NO_2 is commonly called nitrogen oxides or NOx. Other oxides of nitrogen including nitrous acid and nitric acid are part of the nitrogen oxide family. While EPA's National Ambient Air Quality Standard (NAAQS) covers this entire family, NO_2 is the component of greatest interest and the indicator for the larger group of nitrogen oxides.

NOx react with ammonia, moisture, and other compounds to form small particles. These small particles penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory disease, such as emphysema and bronchitis, and can aggravate existing heart disease, leading to increased hospital admissions and premature death.

Ozone is formed when NOx and volatile organic compounds react in the presence of heat and sunlight. Children, the elderly, people with lung diseases such as asthma, and people who work or exercise outside are at risk for adverse effects from ozone. These include reduction in lung function and increased respiratory symptoms as well as respiratory-related emergency department visits, hospital admissions, and possibly premature deaths.

Emissions that lead to the formation of NO_2 generally also lead to the formation of other NOx. Emissions control measures leading to reductions in NO_2 can generally be expected to reduce population exposures to all gaseous NOx. This may have the important co-benefit of reducing the formation of ozone and fine particles both of which pose significant public health threats.

Last updated on Thursday, March 22, 2012

UNEP

World Meteorological Organization

Integrated Assessment of Black Carbon and Tropospheric Ozone

Summary for Decision Makers











A complete elaboration of the topics covered in this summary can be found in the Integrated Assessment of Black Carbon and Tropospheric Ozone report and in the fully referenced underlying research, analyses and reports.

For details of UNEP's regional and sub-regional areas referred to throughout this document see http://geodata.grid.unep.ch/extras/geosubregions.php.

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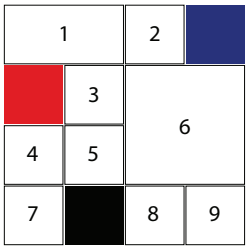
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Integrated Assessment of Black Carbon and Tropospheric Ozone

Summary for Decision Makers

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Main Messages

Scientific evidence and new analyses demonstrate that control of black carbon particles and tropospheric ozone through rapid implementation of proven emission reduction measures would have immediate and multiple benefits for human well-being.

Black carbon exists as particles in the atmosphere and is a major component of soot, it has significant human health and climate impacts. At ground level, ozone is an air pollutant harmful to human health and ecosystems, and throughout the troposphere, or lower atmosphere, is also a significant greenhouse gas. Ozone is not directly emitted, but is produced from emissions of precursors of which methane and carbon monoxide are of particular interest here.

THE CHALLENGE

1. **The climate is changing now, warming at the highest rate in polar and high-altitude regions.** Climate change, even in the near term, has the potential to trigger abrupt transitions such as the release of carbon from thawing permafrost and biodiversity loss. The world has warmed by about 0.8˚C from pre-industrial levels, as reported by the



Credit: Kevin Hicks

Traditional brick kilns in South Asia are a major source of black carbon. Improved kiln design in this region is significantly reducing emissions.

Intergovernmental Panel on Climate Change (IPCC). The Parties to the United Nations Framework Convention on Climate Change (UNFCCC) have agreed that warming should not exceed 2°C above pre-industrial levels.

2. **Black carbon and ozone in the lower atmosphere are harmful air pollutants that have substantial regional and global climate impacts.** They disturb tropical rainfall and regional circulation patterns such as the Asian monsoon, affecting the livelihoods of millions of people.

3. **Black carbon's darkening of snow and ice surfaces increases their absorption of sunlight, which, along with atmospheric heating, exacerbates melting of snow and ice around the world, including in the Arctic, the Himalayas and other glaciated and snow-covered regions.** This affects the water cycle and increases risks of flooding.

4. **Black carbon, a component of particulate matter, and ozone both lead to adverse impacts on human health leading to premature deaths worldwide. Ozone is also the most important air pollutant responsible for reducing crop yields, and thus affects food security.**

REDUCING EMISSIONS

5. **Reducing black carbon and tropospheric ozone now will slow the rate of climate change within the first half of this century. Climate benefits from reduced ozone are achieved by reducing emissions of some of its precursors, especially methane which is also a powerful greenhouse gas.** These short-lived climate forcers – methane, black carbon and ozone – are fundamentally different from longer-lived greenhouse gases, remaining in the atmosphere for only a relatively short time. Deep and immediate carbon dioxide reductions are required to protect long-term climate, as this cannot be achieved by addressing short-lived climate forcers.

6. **A small number of emission reduction measures targeting black carbon and ozone precursors could immediately begin to protect climate, public health, water and food security, and ecosystems.** Measures include the recovery of methane from coal, oil and gas extraction and transport, methane capture in waste management, use of clean-burning stoves for residential cooking, diesel particulate filters for vehicles and the banning of field burning of agricultural waste. Widespread implementation is achievable with existing technology but would require significant strategic investment and institutional arrangements.

7. **The identified measures complement but do not replace anticipated carbon dioxide reduction measures.** Major carbon dioxide reduction strategies mainly target the energy and large industrial sectors and therefore would not necessarily result in significant reductions in emissions of black carbon or the ozone precursors methane and carbon monoxide. Significant reduction of the short-lived climate forcers requires a specific strategy, as many are emitted from a large number of small sources.

BENEFITS OF EMISSION REDUCTIONS

8. **Full implementation of the identified measures would reduce future global warming by 0.5°C (within a range of 0.2–0.7°C, Figure 1).** If the measures were to be implemented by 2030, they could halve the potential increase in global temperature projected for 2050 compared to the Assessment's reference scenario based on current policies and energy and fuel projections. The rate of regional temperature increase would also be reduced.

9. **Both near-term and long-term strategies are essential to protect climate.** Reductions in near-term warming can be achieved by control of the short-lived climate forcers whereas carbon dioxide emission reductions, beginning now, are required to limit long-term climate change. Implementing both reduction strategies is needed to improve the chances of keeping the Earth's global mean temperature increase to within the UNFCCC 2°C target.

10. **Full implementation of the identified measures would have substantial benefits in the Arctic, the Himalayas and other glaciated and snow-covered regions.** This could reduce warming in the Arctic in the next 30 years by about two-thirds compared to the projections of the Assessment's reference scenario. This substantially decreases the risk of changes in weather patterns and amplification of global warming resulting from changes in the Arctic. Regional benefits of the black carbon measures, such as their effects on snow- and ice-covered regions or regional rainfall patterns, are largely independent of their impact on global mean warming.

11. **Full implementation of the identified measures could avoid 2.4 million premature deaths (within a range of 0.7–4.6 million) and the loss of 52 million tonnes (within a range of 30–140 million tonnes), 1–4 per cent, of the global production of maize, rice, soybean and wheat each year (Figure 1).** The most substantial benefits will be felt immediately in or close to the regions where action is taken to reduce emissions, with the greatest health and crop benefits expected in Asia.

RESPONSES

12. The identified measures are all currently in use in different regions around the world to achieve a variety of environment and development objectives. **Much wider and more rapid implementation is required to achieve the full benefits identified in this Assessment.**

13. **Achieving widespread implementation of the identified measures would be most effective if it were country- and region-specific, and could be supported by the considerable existing body of knowledge and experience.** Accounting for near-term climate co-benefits could leverage additional action and funding on a wider international scale which would facilitate more rapid implementation of the measures. Many measures achieve cost savings over time. However, initial capital investment could be problematic in some countries, necessitating additional support and investment.

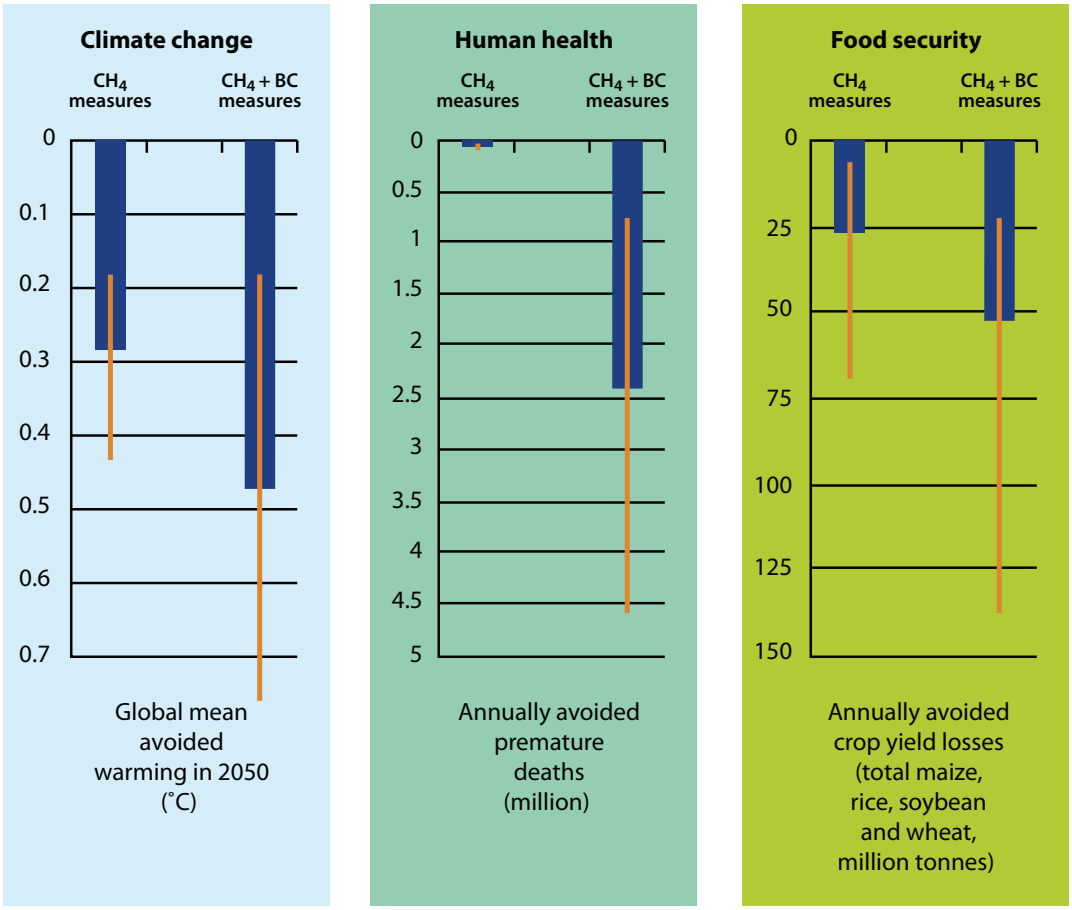


Figure 1. Global benefits from full implementation of the identified measures in 2030 compared to the reference scenario. The climate change benefit is estimated for a given year (2050) and human health and crop benefits are for 2030 and beyond.

14. **At national and sub-national scales many of the identified measures could be implemented under existing policies designed to address air quality and development concerns. Improved cooperation within and between regions would enhance widespread implementation and address transboundary climate and air quality issues.** International policy and financing instruments to address the co-benefits of reducing emissions of short-lived climate forcers need development and strengthening. Supporting and extending existing relevant regional arrangements may provide an opportunity for more effective cooperation, implementation and assessment as well as additional monitoring and research.

15. **The Assessment concludes that there is confidence that immediate and multiple benefits will be realized upon implementation of the identified measures.** The degree of confidence varies according to pollutant, impact and region. For example, there is higher confidence in the effect of methane measures on global temperatures than in the effect of black carbon measures, especially where these relate to the burning of biomass. There is also high confidence that benefits will be realized for human health from reducing particles, including black carbon, and to crop yields from reducing tropospheric ozone concentrations. Given the scientific complexity of the issues, further research is required to optimize near-term strategies in different regions and to evaluate the cost-benefit ratio for individual measures.

Introduction

Black carbon (BC, Box 1) and tropospheric ozone (O_3, Box 2) are harmful air pollutants that also contribute to climate change. In recent years, scientific understanding of how BC and O_3 affect climate and public health has significantly improved. This has catalysed a demand for information and action from governments, civil society and other stakeholders. The United Nations (UN) has been requested to urgently provide science-based advice on action to reduce the impacts of these pollutants[1].

The United Nations Environment Programme (UNEP), in consultation with partners, initiated an assessment designed to provide an interface between knowledge and action, science and policy, and to provide a scientifically credible basis for informed decision-making. The result is a comprehensive analysis of drivers of emissions, trends in concentrations, and impacts on climate, human health and ecosystems of BC, tropospheric O_3 and its precursors. BC, tropospheric O_3 and methane (CH_4) are often referred to as short-lived climate forcers (SLCFs) as they have a short lifetime in the atmosphere (days to about a decade) relative to carbon dioxide (CO_2).

The Assessment is an integrated analysis of multiple co-emitted pollutants reflecting the fact that these pollutants are not emitted in isolation (Boxes 1 and 2). The Assessment determined that under current policies, emissions of BC and O_3 precursors are expected globally either to increase or to remain roughly constant unless further mitigation action is taken.

The Integrated Assessment of Black Carbon and Tropospheric Ozone convened more than 50 authors to assess the state of science and existing policy options for addressing these pollutants. The Assessment team examined policy responses, developed an outlook to 2070 illustrating the benefits of political decisions made today and the risks to climate, human health and crop yields over the next decades if action is delayed. Placing a premium on robust science and analysis, the Assessment was driven by four main policy-relevant questions:

- Which measures are likely to provide significant combined climate and air-quality benefits?
- How much can implementation of the identified measures reduce the rate of global mean temperature increase by mid-century?
- What are the multiple climate, health and crop-yield benefits that would be achieved by implementing the measures?
- By what mechanisms could the measures be rapidly implemented?

In order to answer these questions, the Assessment team determined that new analyses were needed. The Assessment therefore relies on published literature as much as possible and on new simulations by two independent climate-chemistry-aerosol models: one developed and run by the NASA-Goddard Institute for Space Studies (GISS) and the other developed by the Max Planck Institute in Hamburg, Germany (ECHAM), and run at the Joint Research Centre of the European Commission in Ispra, Italy. The specific measures and emission estimates for use in developing this Assessment were selected using the International Institute for Applied Systems Analysis Greenhouse Gas and Air Pollution Interactions and Synergies (IIASA GAINS) model. For a more detailed description of the modelling see Chapter 1.

[1] The Anchorage Declaration of 24 April 2009, adopted by the Indigenous People's Global Summit on Climate Change; the Tromsø Declaration of 29 April 2009, adopted by the Sixth Ministerial Meeting of the Arctic Council and the 8th Session of the Permanent Forum on Indigenous Issues under the United Nations Economic and Social Council (May 2009) called on UNEP to conduct a fast track assessment of short-term drivers of climate change, specifically BC, with a view to initiating the negotiation of an international agreement to reduce emissions of BC. A need to take rapid action to address significant climate forcing agents other than CO_2, such as BC, was reflected in the 2009 declaration of the G8 leaders (Responsible Leadership for a Sustainable Future, L'Aquila, Italy, 2009).

Box 1: What is black carbon?

Black carbon (BC) exists as particles in the atmosphere and is a major component of soot. BC is not a greenhouse gas. Instead it warms the atmosphere by intercepting sunlight and absorbing it. BC and other particles are emitted from many common sources, such as cars and trucks, residential stoves, forest fires and some industrial facilities. BC particles have a strong warming effect in the atmosphere, darken snow when it is deposited, and influence cloud formation. Other particles may have a cooling effect in the atmosphere and all particles influence clouds. In addition to having an impact on climate, anthropogenic particles are also known to have a negative impact on human health.

Black carbon results from the incomplete combustion of fossil fuels, wood and other biomass. Complete combustion would turn all carbon in the fuel into carbon dioxide (CO_2). In practice, combustion is never complete and CO_2, carbon monoxide (CO), volatile organic compounds (VOCs), organic carbon (OC) particles and BC particles are all formed. There is a close relationship between emissions of BC (a warming agent) and OC (a cooling agent). They are always co-emitted, but in different proportions for different sources. Similarly, mitigation measures will have varying effects on the BC/OC mix.

The black in BC refers to the fact that these particles absorb visible light. This absorption leads to a disturbance of the planetary radiation balance and eventually to warming. The contribution to warming of 1 gramme of BC seen over a period of 100 years has been estimated to be anything from 100 to 2 000 times higher than that of 1 gramme of CO_2. An important aspect of BC particles is that their lifetime in the atmosphere is short, days to weeks, and so emission reductions have an immediate benefit for climate and health.



Credit: NASA-MODIS

Haze with high particulate matter concentrations containing BC and OC, such as this over the Bay of Bengal, is widespread in many regions.



Credit: Caramel/flickr

High emitting vehicles are a significant source of black carbon and other pollutants in many countries.



Credit: Luisa Molina

No retrofit system
Uncontrolled Diesel Exhaust
(Level 1)

Old technlogy
Little black carbon removal
Little ultrafine PM removal
Does not remove lube oil ash

Retrofitted with
Diesel Oxidation Catalyst (DOC)
(Level 1)

Old technlogy
Little black carbon removal
Little ultrafine PM removal
Does not remove lube oil ash

Retrofitted with
Partial Filter
(Level 2)

Little black carbon removal
Little ultrafine PM removal
Does not remove lube oil ash

Retrofitted with
Diesel Particulate Filter (DPF)
(Level 3)

New Technology
Used on all new trucks since 2007
>85% black carbon removal
>85% ultrafine removal
>85% lube oil ash removal

Some of the largest emission reductions are obtained using diesel particle filters on high emitting vehicles. The exhibits above are actual particulate matter (PM) collection samples from an engine testing laboratory (International Council of Clean Transportation (ICCT)).

Box 2: What is tropospheric ozone?

Ozone (O_3) is a reactive gas that exists in two layers of the atmosphere: the stratosphere (the upper layer) and the troposphere (ground level to ~10–15 km). In the stratosphere, O_3 is considered to be beneficial as it protects life on Earth from the sun's harmful ultraviolet (UV) radiation. In contrast, at ground level, it is an air pollutant harmful to human health and ecosystems, and it is a major component of urban smog. In the troposphere, O_3 is also a significant greenhouse gas. The threefold increase of the O_3 concentration in the northern hemisphere during the past 100 years has made it the third most important contributor to the human enhancement of the global greenhouse effect, after CO_2 and CH_4.

In the troposphere, O_3 is formed by the action of sunlight on O_3 precursors that have natural and anthropogenic sources. These precursors are CH_4, nitrogen oxides (NO_X), VOCs and CO. It is important to understand that reductions in both CH_4 and CO emissions have the potential to substantially reduce O_3 concentrations and reduce global warming. In contrast, reducing VOCs would clearly be beneficial but has a small impact on the global scale, while reducing NO_X has multiple additional effects that result in its net impact on climate being minimal.



Credit: Luisa Molina



Credit: Warren Gretz/DOE/NREL

Tropospheric ozone is a major constituent of urban smog, left Tokyo, Japan; right Denver, Colorado, USA

Limiting Near-Term Climate Changes and Improving Air Quality

Identifying effective response measures

The Assessment identified those measures most likely to provide combined benefits, taking into account the fact that BC and O_3 precursors are co-emitted with different gases and particles, some of which cause warming and some of which, such as organic carbon (OC) and sulphur dioxide (SO_2) lead to cooling. The selection criterion was that the measure had to be likely to reduce global climate change and also provide air quality benefits, so-called win-win measures. Those measures that provided a benefit for air quality but increased warming were not included in the selected measures. For example, measures that primarily reduce emissions of SO_2 were not included.

The identified measures (Table 1) were chosen from a subset of about 2 000 separate measures that can be applied to sources in IIASA's GAINS model. The selection was based on the net influence on warming, estimated using the metric Global Warming Potential (GWP), of all of the gases and particles that are affected by the measure. The selection gives a useful indication of the potential for realizing a win for climate. All emission reduction measures were assumed to benefit air quality by reducing particulate matter and/or O_3 concentrations.

This selection process identified a relatively small set of measures which nevertheless provide about 90 per cent of the climate benefit compared to the implementation of all 2 000 measures in GAINS. The final analysis of the benefits for temperature, human health and crop yields considered the emissions of all substances resulting from the full implementation of the identified measures through the two global composition-climate models GISS and ECHAM (see Chapter 4). One hundred per cent implementation of the measures globally was used to illustrate the existing potential to reduce climate and air quality impacts, but this does not make any assumptions regarding the feasibility of full implementation everywhere. A discussion of the challenges involved in widespread implementation of the measures follows after the potential benefit has been demonstrated.

Achieving large emission reductions

The packages of policy measures in Table 1 were compared to a reference scenario (Table 2). Figure 2 shows the effect of the packages of policy measures and the reference scenario relative to 2005 emissions.

There is tremendous regional variability in how emissions are projected to change by the year 2030 under the reference scenario. Emissions of CH_4 – a major O_3 precursor and a potent greenhouse gas – are expected to increase in the future (Figure 2). This increase will occur despite current and planned regulations, in large part due to anticipated economic growth and the increase in fossil fuel production projected to accompany it. In contrast, global emissions of BC and accompanying co-emitted pollutants are expected to remain relatively constant through to 2030. Regionally, reductions in BC emissions are expected due to tighter standards on road transport and more efficient combustion replacing use of biofuels in the residential and commercial sectors,

Table 1. Measures that improve climate change mitigation and air quality and have a large emission reduction potential

Measure[1]	Sector
CH_4 measures	
Extended pre-mine degasification and recovery and oxidation of CH_4 from ventilation air from coal mines	Extraction and transport of fossil fuel
Extended recovery and utilization, rather than venting, of associated gas and improved control of unintended fugitive emissions from the production of oil and natural gas	
Reduced gas leakage from long-distance transmission pipelines	
Separation and treatment of biodegradable municipal waste through recycling, composting and anaerobic digestion as well as landfill gas collection with combustion/utilization	Waste management
Upgrading primary wastewater treatment to secondary/tertiary treatment with gas recovery and overflow control	
Control of CH_4 emissions from livestock, mainly through farm-scale anaerobic digestion of manure from cattle and pigs	Agriculture
Intermittent aeration of continuously flooded rice paddies	
BC measures (affecting BC and other co-emitted compounds)	
Diesel particle filters for road and off-road vehicles	Transport
Elimination of high-emitting vehicles in road and off-road transport	
Replacing coal by coal briquettes in cooking and heating stoves	Residential
Pellet stoves and boilers, using fuel made from recycled wood waste or sawdust, to replace current wood-burning technologies in the residential sector in industrialized countries	
Introduction of clean-burning biomass stoves for cooking and heating in developing countries[2, 3]	
Substitution of clean-burning cookstoves using modern fuels for traditional biomass cookstoves in developing countries[2, 3]	
Replacing traditional brick kilns with vertical shaft kilns and Hoffman kilns	Industry
Replacing traditional coke ovens with modern recovery ovens, including the improvement of end-of-pipe abatement measures in developing countries	
Ban of open field burning of agricultural waste[2]	Agriculture

[1] There are measures other than those identified in the table that could be implemented. For example, electric cars would have a similar impact to diesel particulate filters but these have not yet been widely introduced; forest fire controls could also be important but are not included due to the difficulty in establishing the proportion of fires that are anthropogenic.
[2] Motivated in part by its effect on health and regional climate, including areas of ice and snow.
[3] For cookstoves, given their importance for BC emissions, two alternative measures are included.

although these are offset to some extent by increased activity and economic growth. The regional BC emission trends, therefore, vary significantly, with emissions expected to decrease in North America and Europe, Latin America and the Caribbean, and in Northeast Asia, Southeast Asia and the Pacific, and to increase in Africa and South, West and Central Asia.

The full implementation of the selected measures by 2030 leads to significant reductions of SLCF emissions relative to current emissions or to the 2030 emissions in the reference scenario (Figure 2). It also reduces a high proportion of the emissions relative to the maximum reduction from the implementation of all 2 000 or so measures in the GAINS model. The measures designed to

reduce BC also have a considerable impact on OC, total fine particulate matter ($PM_{2.5}$) and CO emissions, removing more than half the total anthropogenic emissions. The largest BC emission reductions are obtained through measures controlling incomplete combustion of biomass and diesel particle filters.

The major sources of CO_2 are different from those emitting most BC, OC, CH_4 and CO. Even in the few cases where there is overlap, such as diesel vehicles, the particle filters that reduce BC, OC and CO have minimal effect on CO_2. The measures to reduce CO_2 over the next 20 years (Table 2) therefore hardly affect the emissions of BC, OC or CO. The influence of the CH_4 and BC measures is thus the same regardless of whether the CO_2 measures are imposed or not.

Reducing near-term global warming

The Earth is projected to continue the rapid warming of the past several decades and, without additional mitigation efforts, under the reference scenario global mean temperatures are projected to rise about a further 1.3˚C (with a range of 0.8–2.0˚C) by the middle of this century, bringing the total warming from pre-industrial levels to about 2.2˚C (Figure 3). The Assessment shows that the measures targeted to reduce emissions of BC and CH_4 could greatly reduce global mean warming rates over the next few decades (Figure 3). Figure 1 shows that over half of the reduced global mean warming is achieved by the CH_4 measures and the remainder by BC measures. The greater confidence in the effect of CH_4 measures on warming is reflected in the narrower range of estimates.

When all measures are fully implemented, warming during the 2030s relative to the present day is only half as much as if no measures had been implemented. In contrast, even a fairly aggressive strategy to reduce CO_2 emissions under the CO_2 measures scenario does little to mitigate warming over the next 20–30 years. In fact, sulphate particles, reflecting particles that offset some of the committed warming for the short time they are in the atmosphere, are derived from SO_2 that is co-emitted with CO_2 in some of the highest-emitting activities, including coal burning in large-scale combustion such as in power plants. Hence, CO_2 measures alone may temporarily enhance near-term warming as sulphates are reduced (Figure 3;

Table 2. Policy packages used in the Assessment

Scenario	Description[1]
Reference	Based on energy and fuel projections of the International Energy Agency (IEA) *World Energy Outlook 2009* and incorporating all presently agreed policies affecting emissions
CH_4 measures	Reference scenario plus the CH_4 measures
BC measures	Reference scenario plus the BC measures (the BC measures affect many pollutants, especially BC, OC, and CO)
CH_4 + BC measures	Reference scenario plus the CH_4 and BC measures
CO_2 measures	Emissions modelled using the assumptions of the IEA *World Energy Outlook 2009* 450 Scenario[2] and the IIASA GAINS database. Includes CO_2 measures only. The CO_2 measures affect other emissions, especially SO_2[3]
CO_2 + CH_4 + BC measures	CO_2 measures plus CH_4 and BC measures

[1] In all scenarios, trends in all pollutant emissions are included through 2030, after which only trends in CO_2 are included.
[2] The 450 Scenario is designed to keep total forcing due to long-lived greenhouse gases (including CH_4 in this case) at a level equivalent to 450 ppm CO_2 by the end of the century.
[3] Emissions of SO_2 are reduced by 35–40 per cent by implementing CO_2 measures. A further reduction in sulphur emissions would be beneficial to health but would increase global warming. This is because sulphate particles cool the Earth by reflecting sunlight back to space.

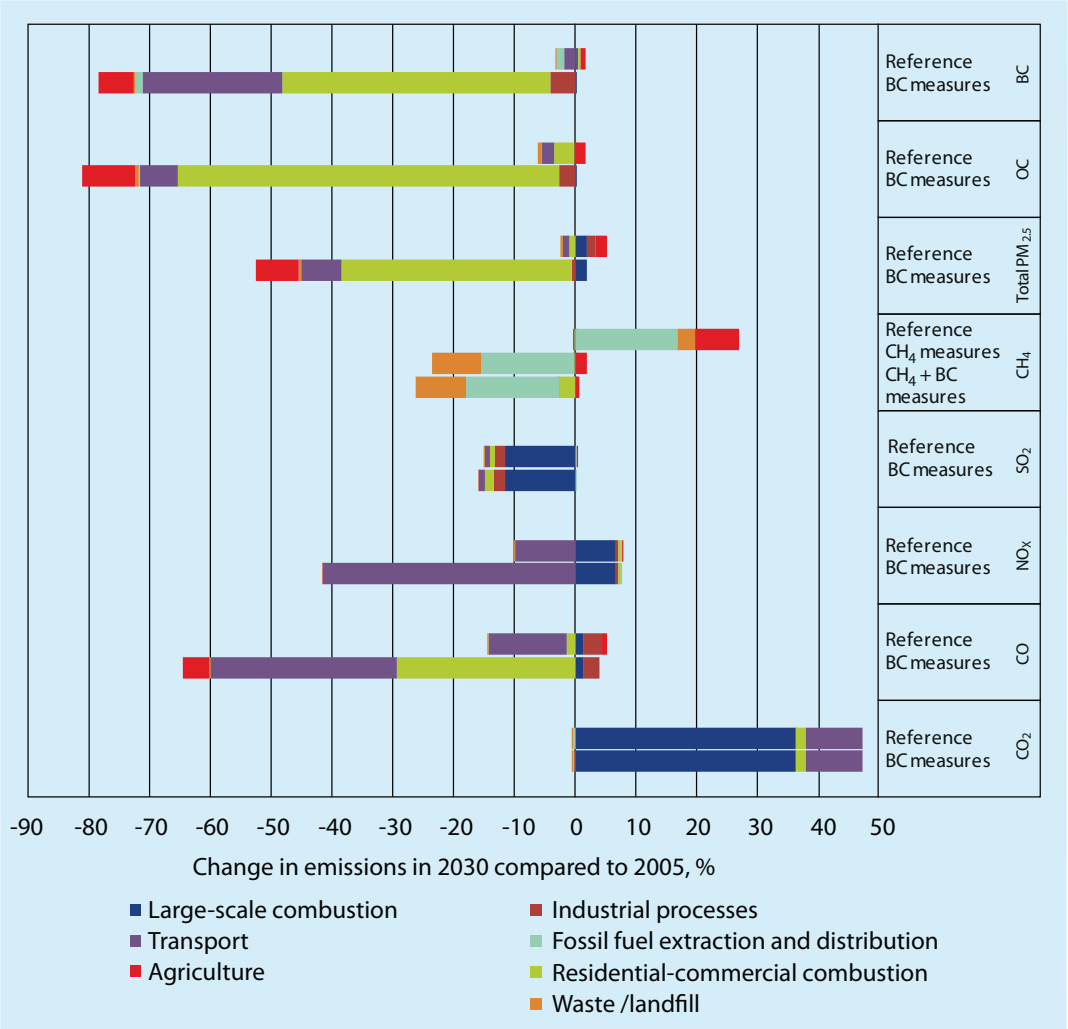


Figure 2. Percentage change in anthropogenic emissions of the indicated pollutants in 2030 relative to 2005 for the reference, CH_4, BC and CH_4 + BC measures scenarios. The CH_4 measures have minimal effect on emissions of anything other than CH_4. The identified BC measures reduce a large proportion of total BC, OC and CO emissions. SO_2 and CO_2 emissions are hardly affected by the identified CH_4 and BC measures, while NO_x and other $PM_{2.5}$ emissions are affected by the BC measures.

temperatures in the CO_2 measures scenario are slightly higher than those in the reference scenario during the period 2020–2040).

The CO_2 measures clearly lead to long-term benefits, with a dramatically lower warming rate in 2070 than under the scenario with only near-term CH_4 + BC measures. Owing to the long residence time of CO_2 in the atmosphere, these long-term benefits will only be achieved if CO_2 emission reductions are brought in quickly. In essence, the near-term CH_4 and BC measures examined in this Assessment are effectively decoupled from the CO_2 measures both in that they target different source sectors and in that their impacts on climate change take place over different timescales.

Near-term warming may occur in sensitive regions and could cause essentially irreversible changes, such as loss of Arctic land-ice, release of CH_4 or CO_2 from Arctic permafrost and species loss. Indeed, the projected warming in the reference scenario is greater in the Arctic than globally. Reducing the near-term rate of warming hence decreases the risk of irreversible transitions that could influence the global climate system for centuries.

Staying within critical temperature thresholds

Adoption of the near-term emission control measures described in this Assessment, together with measures to reduce CO_2 emissions, would greatly improve the chances of keeping Earth's temperature increase to less than 2˚C relative to pre-industrial levels (Figure 3). With the CO_2 measures alone, warming exceeds 2˚C before 2050. Even with both the CO_2 measures and CH_4 measures envisioned under the same IEA 450 Scenario, warming exceeds 2˚C in the 2060s (see Chapter 5). However, the combination of CO_2, CH_4, and BC measures holds the temperature increase below 2˚C until around 2070. While CO_2 emission reductions even larger than those in the CO_2 measures scenario would of course mitigate more warming, actual CO_2 emissions over the past decade have consistently exceeded the most pessimistic emission scenarios of the IPCC. Thus, it seems unlikely that reductions more stringent than those in the CO_2 measures scenario will take place during the next 20 years.

Examining the more stringent UNFCCC 1.5˚C threshold, the CO_2 measures scenario exceeds this by 2030, whereas the near-term measures proposed in the Assessment delay that exceedance until after 2040. Again, while substantially deeper early reductions in CO_2 emissions than those in the CO_2 measures scenario could also delay the crossing of the 1.5˚C temperature threshold, such reductions would undoubtedly be even more difficult to achieve. However, adoption of the Assessment's near-term measures (CH_4 + BC) along with the CO_2 reductions would provide

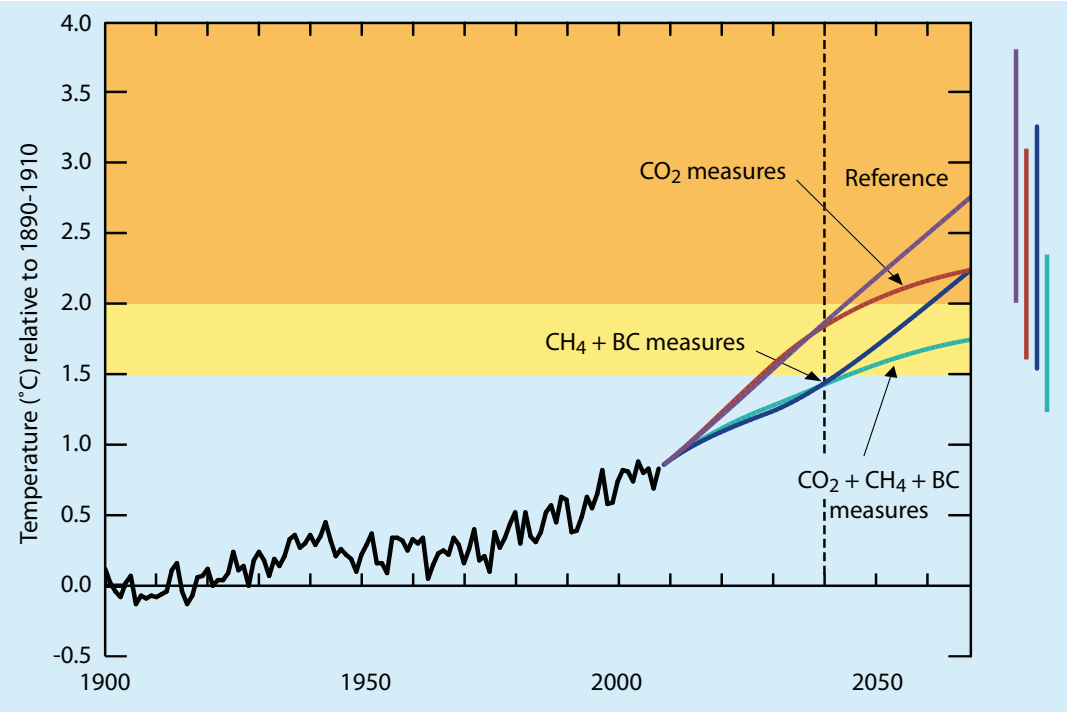


Figure 3. Observed deviation of temperature to 2009 and projections under various scenarios. Immediate implementation of the identified BC and CH_4 measures, together with measures to reduce CO_2 emissions, would greatly improve the chances of keeping Earth's temperature increase to less than 2˚C relative to pre-industrial levels. The bulk of the benefits of CH_4 and BC measure are realized by 2040 (dashed line).
Explanatory notes: Actual mean temperature observations through 2009, and projected under various scenarios thereafter, are shown relative to the 1890–1910 mean temperature. Estimated ranges for 2070 are shown in the bars on the right. A portion of the uncertainty is common to all scenarios, so that overlapping ranges do not mean there is no difference, for example, if climate sensitivity is large, it is large regardless of the scenario, so temperatures in all scenarios would be towards the high-end of their ranges.

a substantial chance of keeping the Earth's temperature increase below 1.5˚C for the next 30 years.

Benefits of early implementation

There would clearly be much less warming during 2020–2060 were the measures implemented earlier rather than later (Figure 4). Hence there is a substantial near-term climate benefit in accelerating implementation of the identified measures even if some of these might eventually be adopted owing to general air-quality and development concerns. Clearly the earlier implementation will also have significant additional human health and crop-yield benefits.

Accelerated adoption of the identified measures has only a modest effect on long-term climate change in comparison with waiting 20 years, however (Figure 4). This reinforces the conclusion that reducing emissions of O_3 precursors and BC can have substantial benefits in the near term, but that mitigating long-term climate change depends on reducing emissions of long-lived greenhouse gases such as CO_2.

Regional climate benefits

While global mean temperatures provide some indication of climate impacts, temperature changes can vary dramatically from place to place even in response to relatively uniform forcing from long-lived greenhouse gases. Figure 5 shows that warming is projected to increase for all regions with some variation under the reference scenario, while the Assessment's measures provide the benefit of reduced warming in all regions.

Climate change also encompasses more than just temperature changes. Precipitation, melting rates of snow and ice, wind patterns, and clouds are all affected, and these in turn have an impact on human well-being by influencing factors such as water availability, agriculture and land use.

Both O_3 and BC, as well as other particles, can influence many of the processes that lead to the formation of clouds and precipitation. They alter surface temperatures, affecting evaporation. By absorbing sunlight in the atmosphere, O_3 and especially BC can affect cloud formation, rainfall and weather patterns. They can change wind patterns by affecting the regional temperature contrasts that drive the winds, influencing where rain and snow fall. While some aspects of these effects are local, they can also affect temperature, cloudiness, and precipitation far away from the emission sources. The regional changes in all these aspects of climate will be significant, but are currently not well quantified.

Tropical rainfall patterns and the Asian monsoon

Several detailed studies of the Asian monsoon suggest that regional forcing by absorbing particles substantially alters precipitation patterns (as explained in the previous section). The fact that both O_3 and particle changes are predominantly in the northern hemisphere means that they cause temperature gradients between the two hemispheres that influence rainfall patterns throughout the tropics. Implementation of the measures analysed in this Assessment would substantially decrease the regional atmospheric heating by particles (Figure 6), and are hence very likely to reduce regional shifts in precipitation. As the reductions of atmospheric forcing are greatest over the Indian sub-continent and other parts of Asia, the emission reductions may have a substantial effect on the Asian monsoon, mitigating disruption of traditional rainfall patterns. However, results from global climate models are not yet robust for the magnitude or timing of monsoon shifts resulting from either greenhouse gas increases or changes in absorbing particles. Nonetheless, results from climate models provide examples of the type of change that might be expected. Shifts in the timing and strength of precipitation can have significant impacts on human well-being because of changes in water

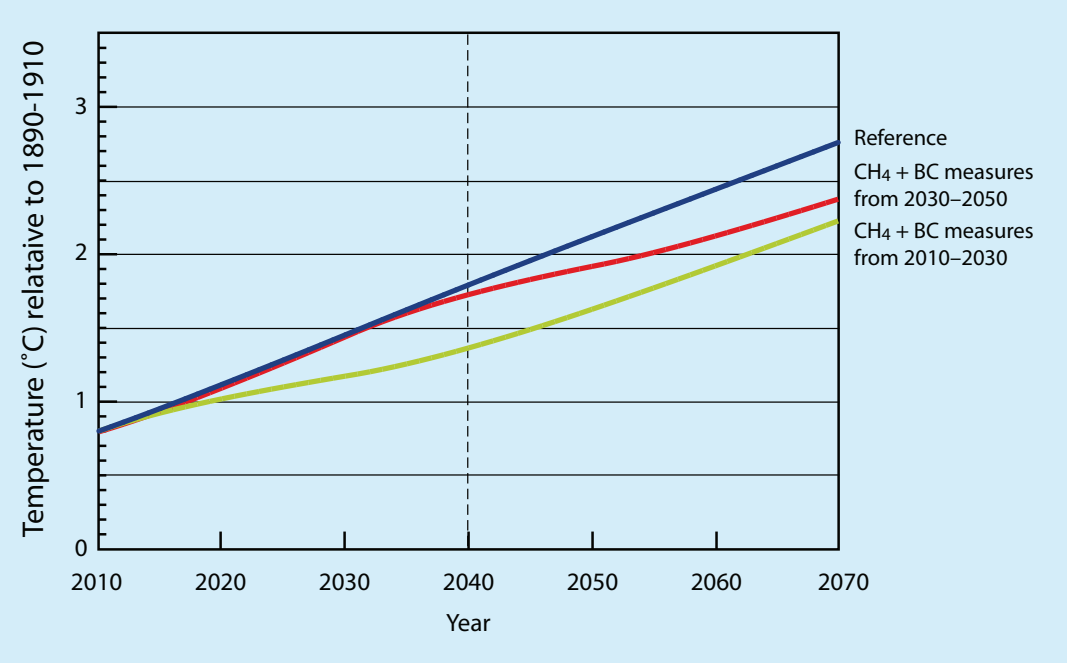


Figure 4. Projected global mean temperature changes for the reference scenario and for the CH_4 and BC measures scenario with emission reductions starting immediately or delayed by 20 years.

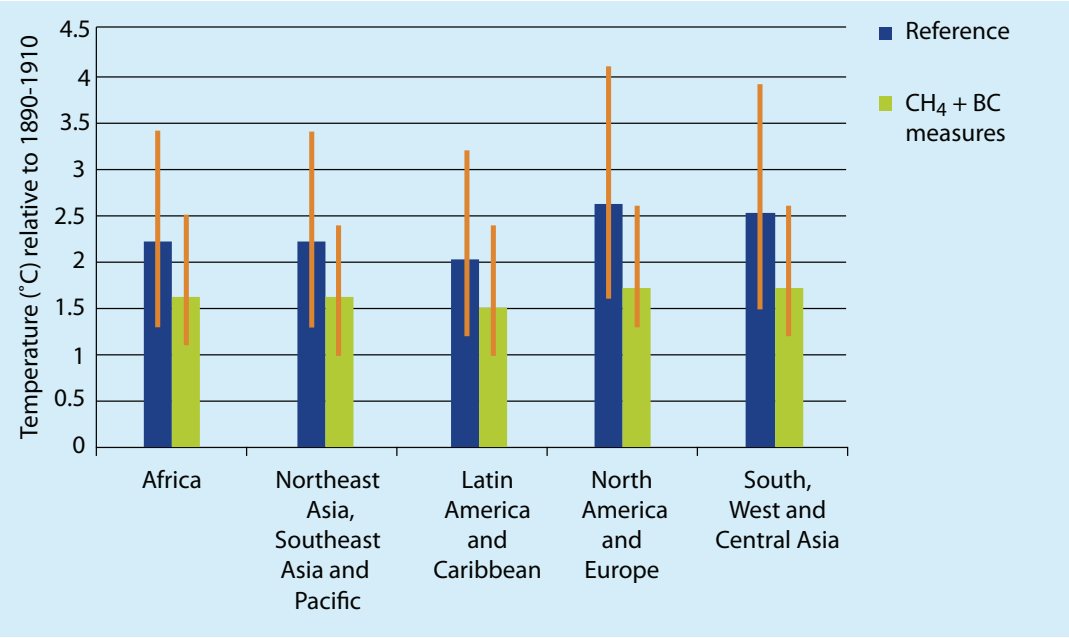


Figure 5. Comparison of regional mean warming over land (˚C) showing the change in 2070 compared with 2005 for the reference scenario (Table 2) and the CH_4 + BC measures scenario. The lines on each bar show the range of estimates.

supply and agricultural productivity, drought and flooding. The results shown in Figure 6 suggest that implementation of the BC measures could also lead to a considerable reduction in the disruption of traditional rainfall patterns in Africa.

Decreased warming in polar and other glaciated regions

Implementation of the measures would substantially slow, but not halt, the current rapid pace of temperature rise and other changes already occurring at the poles and high-altitude glaciated regions, and the reduced warming in these regions would likely be greater than that seen globally. The large benefits occur in part because the snow/ice darkening effect of BC is substantially greater than the cooling effect of reflective particles co-emitted with BC, leading to greater warming impacts in these areas than in areas without snow and ice cover.

Studies in the Arctic indicate that it is highly sensitive both to local pollutant emissions and those transported from sources close to the Arctic, as well as to the climate impact of pollutants in the mid-latitudes of the northern hemisphere. Much of the need for implementation lies within Europe and North America. The identified measures could reduce warming in the Arctic by about 0.7˚C (with a range of 0.2–1.3˚C) in 2040. This is nearly two-thirds of the estimated 1.1˚C (with a range of 0.7–1.7˚C) warming projected for the Arctic under the reference scenario, and should substantially decrease the risk of global impacts from changes in this sensitive region, such as sea ice loss, which affects global albedo, and permafrost melt. Although not identified as a measure for use in this Assessment, the control of boreal forest fires may also be important in reducing impacts in the Arctic.

The Antarctic is a far less studied region in terms of SLCF impacts. However, there are studies demonstrating BC deposition even in central portions of the continent, and reductions in O_3 and CH_4 should slow warming in places like the Antarctic Peninsula, currently the spot on the globe showing the most rapid temperature rise of all.

The Himalayas and the Tibetan Plateau are regions where BC is likely to have serious impacts. In the high valleys of the Himalayas, for example, BC levels can be as high as in

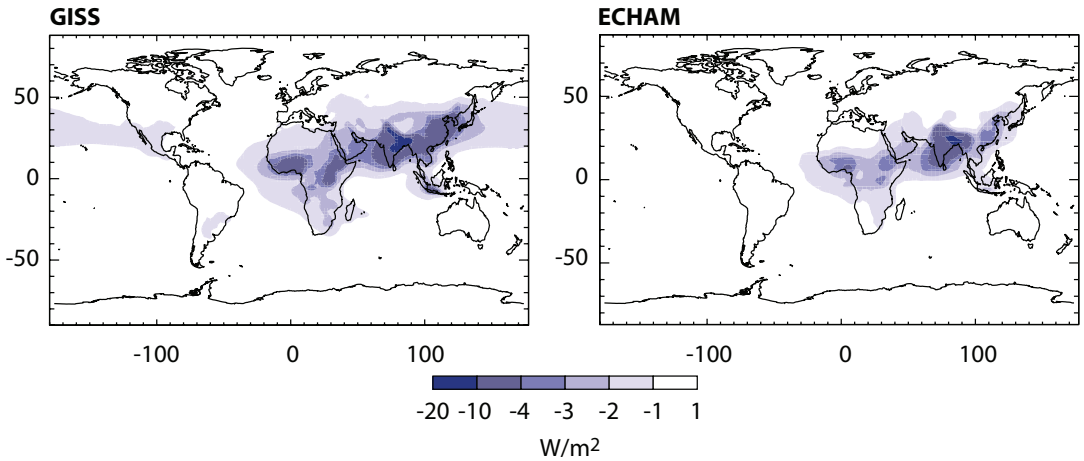


Figure 6. Change in atmospheric energy absorption (Watts per square metre, W/m^2 as annual mean), an important factor driving tropical rainfall and the monsoons resulting from implementation of BC measures. The changes in absorption of energy by the atmosphere are linked with changes in regional circulation and precipitation patterns, leading to increased precipitation in some regions and decreases in others. BC solar absorption increases the energy input to the atmosphere by as much as 5–15 per cent, with the BC measures removing the bulk of that heating. Results are shown for two independent models to highlight the similarity in the projections of where large regional decreases would occur.

a mid-sized city. Reducing emissions from local sources and those carried by long-range transport should lower glacial melt in these regions, decreasing the risk of impacts such as catastrophic glacial lake outbursts.

Benefits of the measures for human health

Fine particulate matter (measured as $PM_{2.5}$, which includes BC) and ground-level O_3 damage human health. $PM_{2.5}$ causes premature deaths primarily from heart disease and lung cancer, and O_3 exposure causes deaths primarily from respiratory illness. The health benefit estimates in the Assessment are limited to changes in these specific causes of death and include uncertainty in the estimation methods. However, these pollutants also contribute significantly to other health impacts including acute and chronic bronchitis and other respiratory illness, non-fatal heart attacks, low birth weight and results in increased emergency room visits and hospital admissions, as well as loss of work and school days.

Under the reference scenario, that is, without implementation of the identified measures, changes in concentrations of $PM_{2.5}$ and O_3 in 2030, relative to 2005, would have substantial effects globally on premature deaths related to air pollution. By region, premature deaths from outdoor pollution are projected to change in line with emissions. The latter are expected to decrease significantly over North America and Europe due to implementation of the existing and expected legislation. Over Africa and Latin America and the Caribbean, the number of premature deaths from these pollutants is expected to show modest changes under the reference scenario (Figure 7). Over Northeast Asia, Southeast Asia and Pacific, premature deaths are projected to decrease substantially due to reductions in $PM_{2.5}$ in some areas. However, in South, West and Central Asia, premature deaths are projected to rise significantly due to growth in emissions.

In contrast to the reference scenario, full implementation of the measures identified in the Assessment would substantially improve air quality and reduce premature deaths globally due to significant reductions in indoor and outdoor air pollution. The reductions in $PM_{2.5}$ concentrations resulting from the BC measures would, by 2030, avoid an estimated 0.7–4.6 million annual premature deaths due to outdoor air pollution (Figure 1).

Regionally, implementation of the identified measures would lead to greatly improved air quality and fewer premature deaths, especially in Asia (Figure 7). In fact, more than 80 per cent of the health benefits of implementing all measures occur in Asia. The benefits are large enough for all the worsening trends in human health due to outdoor air pollution to be reversed and turned into improvements, relative to 2005. In Africa, the benefit is substantial, although not as great as in Asia.

Benefits of the measures for crop yields

Ozone is toxic to plants. A vast body of literature describes experiments and observations showing the substantial effects of O_3 on visible leaf health, growth and productivity for a large number of crops, trees and other plants. Ozone also affects vegetation composition and diversity. Globally, the full implementation of CH_4 measures results in significant reductions in O_3 concentrations leading to avoided yield losses of about 25 million tonnes of four staple crops each year. The implementation of the BC measures would account for about a further 25 million tonnes of avoided yield losses in comparison with the reference scenario (Figure 1). This is due to significant reductions in emissions of the precursors CO, VOCs and NO_X that reduce O_3 concentrations.

The regional picture shows considerable differences. Under the reference scenario, O_3 concentrations over Northeast, Southeast

Asia and Pacific are projected to increase, resulting in additional crop yield losses (Figures 7 and 8). In South, West and Central Asia, both health and agricultural damage are projected to rise (Figure 8). Damage to agriculture is projected to decrease strongly over North America and Europe while changing minimally over Africa and Latin America and the Caribbean. For the whole Asian region maize yields show a decrease of 1–15 per cent, while yields decrease by less than 5 per cent for wheat and rice. These yield losses translate into nearly 40 million tonnes for all crops for the whole Asian region, reflecting the substantial cultivated area exposed to elevated O_3 concentrations in India – in particular the Indo-Gangetic Plain region. Rice production is also affected, particularly in Asia where elevated O_3 concentrations are likely to continue to increase to 2030. Yield loss values for rice are uncertain, however, due to a lack of experimental evidence on concentration-response functions. In contrast, the European and North American regional analyses suggest that all crops will see an improvement in yields under the reference scenario between 2005 and 2030. Even greater improvements would be seen upon implementation of the measures.

The identified measures lead to greatly reduced O_3 concentrations, with substantial benefits to crop yields, especially in Asia (Figure 8). The benefits of the measures are large enough to reverse all the worsening trends seen in agricultural yields and turn them into improvements, relative to 2005, with the exception of crop yields in Northeast and Southeast Asia and Pacific. Even in that case, the benefits of full implementation are quite large, with the measures reducing by 60 per cent the crop losses envisaged in the reference scenario.

It should be stressed that the Assessment's analyses include only the direct effect of changes in atmospheric composition on health and agriculture through changes in exposure to pollutants. As such, they do not include the benefits that avoided climate change would have on human health and agriculture due to factors such as reduced disruption of precipitation patterns, dimming, and reduced frequency of heat waves. Furthermore, even the direct influence on yields are based on estimates for only four staple crops, and impacts on leafy crops, productive grasslands and food quality were not included, so that the calculated values are likely to be an

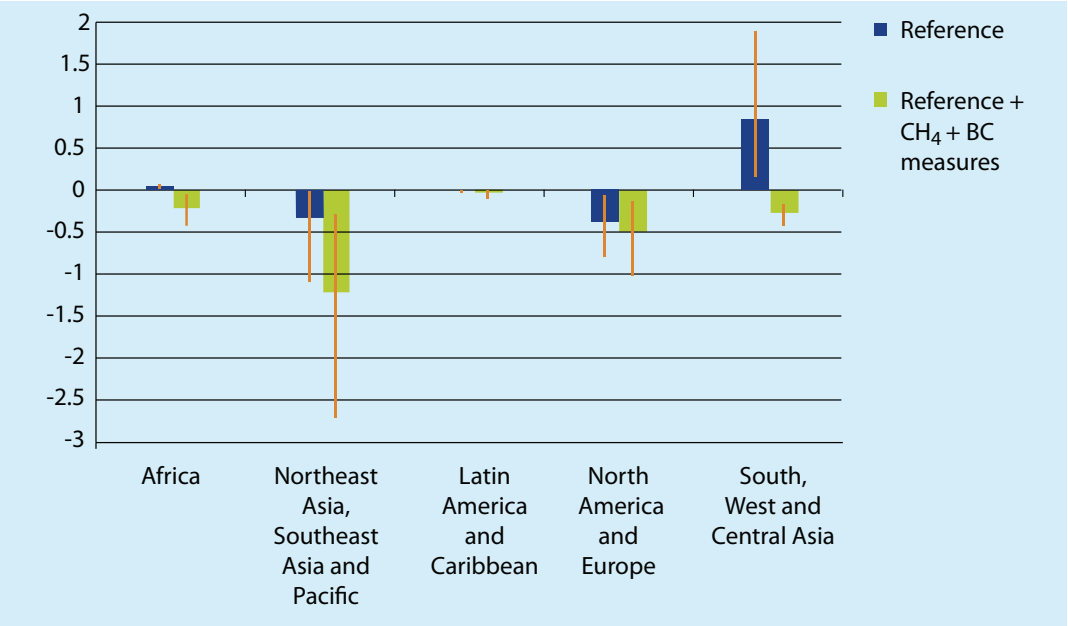


Figure 7. Comparison of premature mortality (millions of premature deaths annually) by region, showing the change in 2030 in comparison with 2005 for the reference scenario emission trends and the reference plus CH_4 + BC measures. The lines on each bar show the range of estimates.



Credit: Veerabhadran Ramanathan

The measures identified in the Assessment include replacement of traditional cookstoves, such as that shown here, with clean burning stoves which would substantially improve air quality and reduce premature deaths due to indoor and outdoor air pollution.

underestimate of the total impact. In addition, extrapolation of results from a number of experimental studies to assess O_3 impacts on ecosystems strongly suggests that reductions in O_3 could lead to substantial increases in the net primary productivity. This could have a substantial impact on carbon sequestration, providing additional climate benefits.

Relative importance and scientific confidence in the measures

Methane measures have a large impact on global and regional warming, which is achieved by reducing the greenhouse gases CH_4 and O_3. The climate mitigation impacts of the CH_4 measures are also the most certain because there is a high degree of confidence in the warming effects of this greenhouse gas. The reduced methane and hence O_3 concentrations also lead to significant benefits for crop yields.

The BC measures identified here reduce concentrations of BC, OC and O_3 (largely through reductions in emissions of CO). The warming effect of BC and O_3 and the compensating cooling effect of OC, introduces large uncertainty in the net effect of some BC measures on global warming (Figure 1). Uncertainty in the impact of BC measures is also larger than that for CH_4 because BC and OC can influence clouds that have multiple effects on climate that are not fully understood. This uncertainly in global impacts is particularly large for the

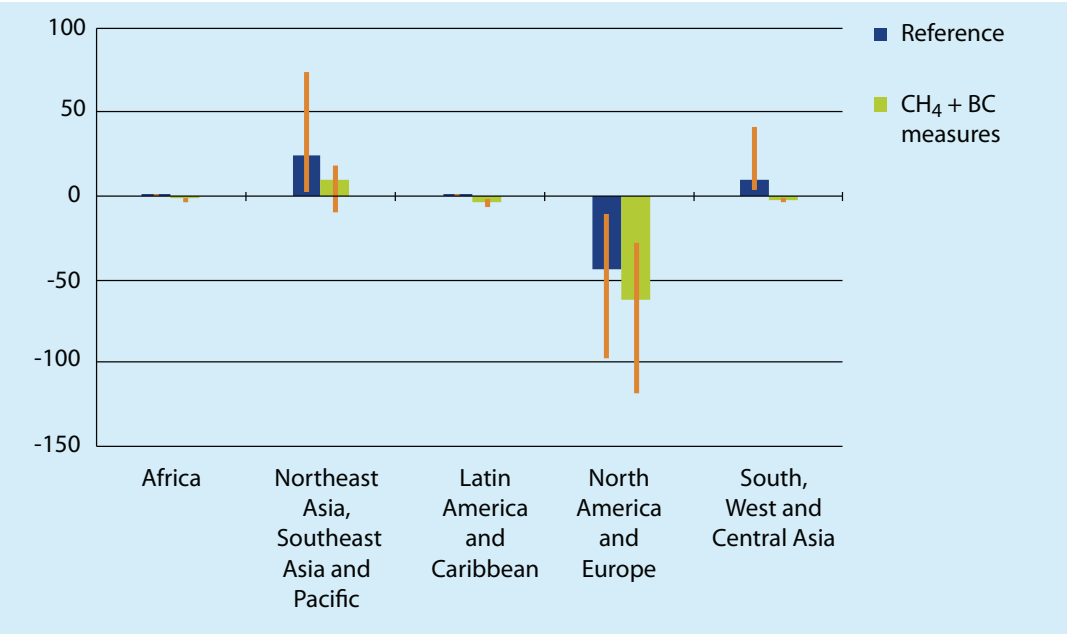


Figure 8. Comparison of crop yield losses (million tonnes annually of four key crops – wheat, rice, maize and soy combined) by region, showing the change in 2030 compared with 2005 for the reference emission trends and the reference with CH_4 + BC measures. The lines on each bar show the range of estimates.



Credit: Veerabhadran Ramanathan

Widespread haze over the Himalayas where BC concentrations can be as high as in mid-sized cities.



Credit: Govind Joshi

Reducing emissions should lower glacial melt and decrease the risk of outbursts from glacial lakes.

measures concerning biomass cookstoves and open burning of biomass. Hence with respect to global warming, there is much higher confidence for measures that mitigate diesel emissions than biomass burning because the proportion of co-emitted cooling OC particles is much lower for diesel.

On the other hand, there is higher confidence that BC measures have large impacts on human health through reducing concentrations of inhalable particles, on crop yields through reduced O_3, and on climate phenomena such as tropical rainfall, monsoons and snow-ice melt. These regional impacts are largely independent of the measures' impact on global warming. In fact, regionally, biomass cookstoves and open biomass burning can have much larger effects than fossil fuels. This is because BC directly increases atmospheric heating by absorbing sunlight, which, according to numerous published studies, affects the monsoon and tropical rainfall, and this is largely separate from the effect of co-emitted OC. The same conclusion applies with respect to the impact of BC measures on snow and ice. BC, because it is dark, significantly increases absorption of sunlight by snow and ice when it is deposited on these bright surfaces. OC that is deposited along with BC has very little effect on sunlight reflected by snow and ice since these surfaces are already very white. Hence knowledge of these regional impacts is, in some cases, more robust than the global impacts, and with respect to reducing regional impacts, all of the BC measures are likely to be significant. Confidence is also high that a large proportion of the health and crop benefits would be realized in Asia.

Mechanisms for rapid implementation

In December 2010 the Parties to the UNFCCC agreed that warming should not exceed 2°C above pre-industrial levels during this century. This Assessment shows that measures to reduce SLCFs, implemented in combination with CO_2 control measures, would increase the chances of staying below the 2°C target. The measures would also slow the rate of near-term temperature rise and also lead to significant improvements in health, decreased disruption of regional precipitation patterns and water supply, and in improved food security. The impacts of the measures on temperature change are felt over large geographical areas, while the air quality impacts are more localized near the regions where changes in emissions take place. Therefore, areas that control their emissions will receive the greatest human health and food supply benefits; additionally many of the climate benefits will be felt close to the region taking action.

The benefits would be realized in the near term, thereby providing additional incentives to overcome financial and institutional hurdles to the adoption of these measures. Countries in all regions have successfully implemented the identified measures to some degree for multiple environment and development objectives. These experiences



Credit: Brian Yap

Field burning of agricultural waste is a common way to dispose of crop residue in many regions.

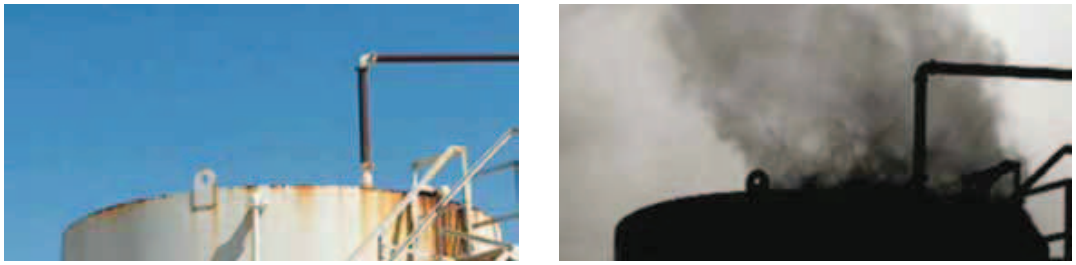
provide a considerable body of knowledge and potential models for others that wish to take action.

In most countries, mechanisms are already in place, albeit at different levels of maturity, to address public concern regarding air pollution problems. Mechanisms to tackle anthropogenic greenhouse gases are less well deployed, and systems to maximize the co-benefits from reducing air pollution and measures to address climate change are virtually non-existent. Coordination across institutions to address climate, air pollution, energy and development policy is particularly important to enhance achievement of all these goals simultaneously.

Many BC control measures require implementation by multiple actors on diffuse emission sources including diesel vehicles, field burning, cookstoves and residential heating. Although air quality and emission standards exist for particulate matter in some regions, they may or may not reduce BC, and implementation remains a challenge. Relevance, benefits and costs of different measures vary from region to region. Many of the measures entail cost savings but require substantial upfront investments. Accounting for air quality, climate and development co-benefits will be key to scaling up implementation.

Methane is one of the six greenhouse gases governed by the Kyoto Protocol, but there are no explicit targets for it. Many CH_4 measures are cost-effective and its recovery is, in many cases, economically profitable. There have been many Clean Development Mechanism (CDM) projects in key CH_4 emitting sectors in the past, though few such projects have been launched in recent years because of lack of financing.

Case studies from both developed and developing countries (Box 3) show that there are technical solutions available to deliver all of the measures (see Chapter 5). Given appropriate policy mechanisms the measures can be implemented, but to achieve the benefits at the scale described much wider implementation is required.



Credit: US EPA

To the naked eye, no emissions from an oil storage tank are visible (left), but with the aid of an infrared camera, escaping CH_4 is evident (right).

Box 3: Case studies of implementation of measures

CH_4 measures

Landfill biogas energy

Landfill CH_4 emissions contribute 10 per cent of the total greenhouse gas emissions in Mexico. Bioenergia de Nuevo Léon S.A. de C.V. (BENLESA) is using landfill biogas as fuel. Currently, the plant has an installed capacity of 12.7 megawatts. Since its opening in September 2003, it has avoided the release of more than 81 000 tonnes of CH_4, equivalent to the reduction in emissions of 1.7 million tonnes of CO_2, generating 409 megawatt hours of electricity. A partnership between government and a private company turned a liability into an asset by converting landfill gas (LFG) into electricity to help drive the public transit system by day and light city streets by night. LFG projects can also be found in Armenia, Brazil, China, India, South Africa, and other countries.

Recovery and flaring from oil and natural gas production

Oil drilling often brings natural gas, mostly CH_4, to the surface along with the oil, which is often vented to the atmosphere to maintain safe pressure in the well. To reduce these emissions, associated gas may be flared and converted to CO_2, or recovered, thus eliminating most of its warming potential and removing its ability to form ozone (O_3). In India, Oil India Limited (OIL), a national oil company, is undertaking a project to recover the gas, which is presently flared, from the Kumchai oil field, and send it to a gas processing plant for eventual transport and use in the natural gas grid. Initiatives in Angola, Indonesia and other countries are flaring and recovering associated gas yielding large reductions in CH_4 emissions and new sources of fuel for local markets.

Livestock manure management

In Brazil, a large CDM project in the state of Mina Gerais seeks to improve waste management systems to reduce the amount of CH_4 and other greenhouse gas emissions associated with animal effluent. The core of the project is to replace open-air lagoons with ambient temperature anaerobic digesters to capture and combust the resulting biogas. Over the course of a 10-year period (2004–2014) the project plans to reduce CH_4 and other greenhouse gas emissions by a total of 50 580 tonnes of CO_2 equivalent. A CDM project in Hyderabad, India, will use the poultry litter CH_4 to generate electricity which will power the plant and supply surplus electricity to the Andhra Pradesh state grid.



Credit: Raphaël V/flickr

Farm scale anaerobic digestion of manure from cattle is one of the key CH_4 measures

Box 3: Case studies of implementation of measures *(continued)*

BC measures

Diesel particle filters

In Santiago, municipal authorities, responding to public concern on air pollution, adopted a new emissions standard for urban buses, requiring installation of diesel particle filters (DPFs). Currently about one-third of the fleet is equipped with filters; it is expected that the entire fleet will be retrofitted by 2018. New York City adopted regulations in 2000 and 2003 requiring use of DPFs in city buses and off-road construction equipment working on city projects. London fitted DPFs to the city's bus fleet over several years beginning in 2003. Low emission zones in London and other cities create incentives for diesel vehicle owners to retrofit with particle filters, allowing them to drive within the city limits. Implementation in developing regions will require greater availability of low sulphur diesel, which is an essential prerequisite for using DPFs.

Improved brick kilns

Small-scale traditional brick kilns are a significant source of air pollution in many developing countries; there are an estimated 20 000 in Mexico alone, emitting large quantities of particulates. An improved kiln design piloted in Ciudad Juárez, near the border with the United States of America, improved efficiency by 50 per cent and decreased particulate pollution by 80 per cent. In the Bac Ninh province of Viet Nam, a project initiated with the aim of reducing ambient air pollution levels and deposition on surrounding rice fields piloted the use of a simple limestone scrubbing emissions control device and demonstrated how a combination of regulation, economic tools, monitoring and technology transfer can significantly improve air quality.



Credit: Alba Corral Avitia



Credit: Robert Marquez

A traditional brick kiln (left) and an improved (right) operating in Mexico.

Potential international regulatory responses

International responses would facilitate rapid and widespread implementation of the measures. Since a large portion of the impacts of SLCFs on climate, health, food security and ecosystems is regional or local in nature, regional approaches incorporating national actions could prove promising for their cost-effective reduction. This approach is still in its very early stage in most regions of the world. For example, the Convention on Long-Range Transboundary Air Pollution (CLRTAP) recently agreed to address BC in the revision of the Gothenburg Protocol in 2011 and to consider the impacts of CH_4 as an O_3 precursor in the longer term.

Other regional agreements (Box 4) are fairly new, and predominantly concentrate on scientific cooperation and capacity building. These arrangements might serve as a platform from which to address the emerging challenges related to air pollution from BC and tropospheric O_3 and provide potential vehicles for finance, technology transfer and capacity development. Sharing good practices

Box 4: Examples of regional atmospheric pollution agreements

The Convention on Long-Range Transboundary Air Pollution (CLRTAP) is a mature policy framework covering Europe, Central Asia and North America. Similar regional agreements have emerged in the last decades in other parts of the world. The Malé Declaration on Control and Prevention of Air Pollution and its Likely Transboundary Effects for South Asia was agreed in 1998 and addresses air quality including tropospheric O_3 and particulate matter. The Association of Southeast Asian Nations (ASEAN) Haze Protocol is a legally binding agreement addresses particulate pollution from forest fires in Southeast Asia. In Africa there are a number of framework agreements between countries in southern Africa (Lusaka Agreement), in East Africa (Nairobi Agreement); and West and Central Africa (Abidjan Agreement). In Latin America and the Caribbean a ministerial level intergovernmental network on air pollution has been formed and there is a draft framework agreement and ongoing collaboration on atmospheric issues under UNEP's leadership.

on an international scale, as is occurring within the Arctic Council, in a coordinated way could provide a helpful way forward.

This Assessment did not assess the cost-effectiveness of different identified measures or policy options under different national circumstances. Doing so would help to inform national air quality and climate policy makers, and support implementation on a wider scale. Further study and analyses of the local application of BC and tropospheric O_3 reduction technologies, costs and regulatory approaches could contribute to advancing adoption of effective action at multiple levels. This work would be best done based on local knowledge. Likewise further evaluation of the regional and global benefits of implementing specific measures by region would help to better target policy efforts. In support of these efforts, additional modelling and monitoring and measurement activities are needed to fill remaining knowledge gaps.

Opportunities for international financing and cooperation

The largest benefits would be delivered in regions where it is unlikely that significant national funds would be allocated to these issues due to other pressing development needs. International financing and technology support would catalyse and accelerate the adoption of the identified measures at sub-national, national and regional levels, especially in developing countries. Financing would be most effective if specifically targeted towards pollution abatement actions that maximize air quality and climate benefits.

Funds and activities to address CH_4 (such as the Global Methane Initiative; and the Global Methane Fund or Prototype Methane Financing Facility) and cookstoves (the Global Alliance for Clean Cookstoves) exist or are under consideration and may serve as models for other sectors. Expanded action will depend on donor recognition of the opportunity represented by SLCF reductions as a highly effective means to address near-term climate change both globally and especially in sensitive regions of the world.

Black carbon and tropospheric O_3 may also be considered as part of other environment, development and energy initiatives such as bilateral assistance, the UN Development Assistance Framework, the World Bank Energy Strategy, the Poverty and Environment Initiative of UNEP and the United Nations Development Programme (UNDP), interagency cooperation initiatives in the UN system such as the Environment Management Group and UN Energy, the UN Foundation, and the consideration by the UN Conference on Sustainable Development (Rio+20) of the institutional framework for sustainable development. These, and others, could take advantage of the opportunities identified in the Assessment to achieve their objectives.



Credit: John Ogren, NOAA

Aerosol measurement instruments



Credit: Christian Lagerek

Concluding Remarks

The Assessment establishes the climate co-benefits of air-quality measures that address black carbon and tropospheric ozone and its precursors, especially CH_4 and CO. The measures identified to address these short-lived climate forcers have been successfully tried around the world and have been shown to deliver significant and immediate development and environmental benefits in the local areas and regions where they are implemented.

Costs and benefits of the identified measures are region specific, and implementation often faces financial, regulatory and institutional barriers. However, widespread implementation of the identified measures can be effectively leveraged by recognizing that near-term strategies can slow the rate of global and regional warming, improving our chances of keeping global temperature increase below bounds that significantly lower the probability of major disruptive climate events. Such leverage should spur multilateral initiatives that focus on local priorities and contribute to the global common good.

It is nevertheless stressed that this Assessment does not in any way suggest postponing immediate and aggressive global action on anthropogenic greenhouse gases; in fact it requires such action on CO_2. This Assessment concludes that the chance of success with such longer-term measures can be greatly enhanced by simultaneously addressing short-lived climate forcers.

The benefits identified in this Assessment can be realised with a concerted effort globally to reduce the concentrations of black carbon and tropospheric ozone. A strategy to achieve this, when developed and implemented, will lead to considerable benefits for human well-being.

Glossary

Aerosol	A collection of airborne solid or liquid particles (excluding pure water), with a typical size between 0.01 and 10 micrometers (μm) and residing in the atmosphere for at least several hours. Aerosols may be of either natural or anthropogenic origin. Aerosols may influence climate in two ways: directly through scattering or absorbing radiation, and indirectly through acting as condensation nuclei for cloud formation or modifying the optical properties and lifetime of clouds.
Biofuels	Biofuels are non-fossil fuels. They are energy carriers that store the energy derived from organic materials (biomass), including plant materials and animal waste.
Biomass	In the context of energy, the term biomass is often used to refer to organic materials, such as wood and agricultural wastes, which can be burned to produce energy or converted into a gas and used for fuel.
Black carbon	Operationally defined aerosol species based on measurement of light absorption and chemical reactivity and/or thermal stability. Black carbon is formed through the incomplete combustion of fossil fuels, biofuel, and biomass, and is emitted in both anthropogenic and naturally occurring soot. It consists of pure carbon in several linked forms. Black carbon warms the Earth by absorbing heat in the atmosphere and by reducing albedo, the ability to reflect sunlight, when deposited on snow and ice.
Carbon sequestration	The uptake and storage of carbon. Trees and plants, for example, absorb carbon dioxide, release the oxygen and store the carbon.
Fugitive emissions	Substances (gas, liquid, solid) that escape to the air from a process or a product without going through a smokestack; for example, emissions of methane escaping from coal, oil, and gas extraction not caught by a capture system.
Global warming potential (GWP)	The global warming potential of a gas or particle refers to an estimate of the total contribution to global warming over a particular time that results from the emission of one unit of that gas or particle relative to one unit of the reference gas, carbon dioxide, which is assigned a value of one.
High-emitting vehicles	Poorly tuned or defective vehicles (including malfunctioning emission control system), with emissions of air pollutants (including particulate matter) many times greater than the average.
Hoffman kiln	Hoffmann kilns are the most common kiln used in production of bricks. A Hoffmann kiln consists of a main fire passage surrounded on each side by several small rooms which contain pallets of bricks. Each room is connected to the next room by a passageway carrying hot gases from the fire. This design makes for a very efficient use of heat and fuel.
Incomplete combustion	A reaction or process which entails only partial burning of a fuel. Combustion is almost always incomplete and this may be due to a lack of oxygen or low temperature, preventing the complete chemical reaction.
Oxidation	The chemical reaction of a substance with oxygen or a reaction in which the atoms in an element lose electrons and its valence is correspondingly increased.

Ozone	Ozone, the triatomic form of oxygen (O_3), is a gaseous atmospheric constituent. In the troposphere, it is created both naturally and by photochemical reactions involving gases resulting from human activities (it is a primary component of photochemical smog). In high concentrations, tropospheric ozone can be harmful to a wide range of living organisms. Tropospheric ozone acts as a greenhouse gas. In the stratosphere, ozone is created by the interaction between solar ultraviolet radiation and molecular oxygen. Stratospheric ozone provides a shield from ultraviolet B (UVB) radiation.
Ozone precursor	Chemical compounds, such as carbon monoxide (CO), methane (CH_4), non-methane volatile organic compounds (NMVOC), and nitrogen oxides (NO_x), which in the presence of solar radiation react with other chemical compounds to form ozone in the troposphere.
Particulate matter	Very small pieces of solid or liquid matter such as particles of soot, dust, or other aerosols.
Pre-industrial	Prior to widespread industrialisation and the resultant changes in the environment. Typically taken as the period before 1750.
Radiation	Energy transfer in the form of electromagnetic waves or particles that release energy when absorbed by an object.
Radiative forcing	Radiative forcing is a measure of the change in the energy balance of the Earth-atmosphere system with space. It is defined as the change in the net, downward minus upward, irradiance (expressed in Watts per square metre) at the tropopause due to a change in an external driver of climate change, such as, for example, a change in the concentration of carbon dioxide or the output of the Sun.
Smog	Classically a combination of smoke and fog in which products of combustion, such as hydrocarbons, particulate matter and oxides of sulphur and nitrogen, occur in concentrations that are harmful to human beings and other organisms. More commonly, it occurs as photochemical smog, produced when sunlight acts on nitrogen oxides and hydrocarbons to produce tropospheric ozone.
Stratosphere	Region of the atmosphere between the troposphere and mesosphere, having a lower boundary of approximately 8 km at the poles to 15 km at the equator and an upper boundary of approximately 50 km. Depending upon latitude and season, the temperature in the lower stratosphere can increase, be isothermal, or even decrease with altitude, but the temperature in the upper stratosphere generally increases with height due to absorption of solar radiation by ozone.
Trans-boundary movement	Movement from an area under the national jurisdiction of one State to or through an area under the national jurisdiction of another State or to or through an area not under the national jurisdiction of any State.
Transport (atmospheric)	The movement of chemical species through the atmosphere as a result of large-scale atmospheric motions.
Troposphere	The lowest part of the atmosphere from the surface to about 10 km in altitude in mid-latitudes (ranging from 9 km in high latitudes to 16 km in the tropics on average) where clouds and "weather" phenomena occur. In the troposphere temperatures generally decrease with height.

Acronyms and Abbreviations

ASEAN	Association of Southeast Asian Nations
BC	black carbon
BENLESA	Latin America Bioenergia de Nuevo Léon S.A. de C.V.
CDM	Clean Development Mechanism
CH_4	methane
CLRTAP	Convention on Long-Range Transboundary Air Pollution
CO	carbon monoxide
CO_2	carbon dioxide
DPF	diesel particle filter
ECHAM	Climate-chemistry-aerosol model developed by the Max Planck Institute in Hamburg, Germany
G8	Group of Eight: Canada, France, Germany, Italy, Japan, Russian Federation, United Kingdom, United States
GAINS	Greenhouse Gas and Air Pollution Interactions and Synergies
GISS	Goddard Institute for Space Studies
GWP	global warming potential
IEA	International Energy Agency
IIASA	International Institute for Applied System Analysis
IPCC	Intergovernmental Panel on Climate Change
LFG	landfill gas
NASA	National Aeronautics and Space Administration
NO_x	nitrogen oxides
O_3	ozone
OC	organic carbon
OIL	Oil India Limited
PM	particulate matter ($PM_{2.5}$ has a diameter of 2.5µm or less)
ppm	parts per million
SLCF	short-lived climate forcer
SO_2	sulphur dioxide
UN	United Nations
UNDP	United Nations Development Programme
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
UV	ultraviolet
VOC	volatile organic compound
WMO	World Meteorological Organization

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About the Assessment:

Growing scientific evidence of significant impacts of black carbon and tropospheric ozone on human well-being and the climatic system has catalysed a demand for information and action from governments, civil society and other main stakeholders. The United Nations, in consultation with partner expert institutions and stakeholder representatives, organized an integrated assessment of black carbon and tropospheric ozone, and its precursors, to provide decision makers with a comprehensive assessment of the problem and policy options needed to address it.

An assessment team of more than 50 experts was established, supported by the United Nations Environment Programme, World Meteorological Organization and Stockholm Environment Institute. The Assessment was governed by the Chair and four Vice-Chairs, representing Asia and the Pacific, Europe, Latin America and the Caribbean and North America regions. A High-level Consultative Group, comprising high-profile government advisors, respected scientists, representatives of international organizations and civil society, provided strategic advice on the assessment process and preparation of the *Summary for Decision Makers*.

The draft of the underlying Assessment and its *Summary for Decision Makers* were extensively reviewed and revised based on comments from internal and external review experts. Reputable experts served as review editors to ensure that all substantive expert review comments were afforded appropriate consideration by the authors. The text of the *Summary for Decision Makers* was accepted by the Assessment Chair, Vice-Chairs and the High-level Consultative Group members.

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This document summarizes findings and conclusions of the assessment report: Integrated Assessment of Black Carbon and Tropospheric Ozone. The assessment looks into all aspects of anthropogenic emissions of black carbon and tropospheric ozone precursors, such as methane. It analyses the trends in emissions of these substances and the drivers of these emissions; summarizes the science of atmospheric processes where these substances are involved; discusses related impacts on the climatic system, human health, crops in vulnerable regions and ecosystems; and societal responses to the environmental changes caused by those impacts. The Assessment examines a large number of potential measures to reduce harmful emissions, identifying a small set of specific measures that would likely produce the greatest benefits, and which could be implemented with currently available technology. An outlook up to 2070 is developed illustrating the benefits of those emission mitigation policies and measures for human well-being and climate. The Assessment concludes that rapid mitigation of anthropogenic black carbon and tropospheric ozone emissions would complement carbon dioxide reduction measures and would have immediate benefits for human well-being.

The Summary for Decision Makers was prepared by a writing team with inputs from the members of the High-level Consultative Group and with support from UNEP and WMO. It is intended to serve decision makers at all levels as a guide for assessment, planning and management for the future.

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EPA United States Environmental Protection Agency

Carbon Monoxide

Health

CO can cause harmful health effects by reducing oxygen delivery to the body's organs (like the heart and brain) and tissues. At extremely high levels, CO can cause death.

Exposure to CO can reduce the oxygen-carrying capacity of the blood. People with several types of heart disease already have a reduced capacity for pumping oxygenated blood to the heart, which can cause them to experience myocardial ischemia (reduced oxygen to the heart), often accompanied by chest pain (angina), when exercising or under increased stress. For these people, short-term CO exposure further affects their body's already compromised ability to respond to the increased oxygen demands of exercise or exertion.

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Regulatory Impact Analysis

Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry

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July 2011

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1 EXECUTIVE SUMMARY

1.1 Background

The U.S. Environmental Protection Agency (EPA) reviewed the New Source Performance Standards (NSPS) for volatile organic compound and sulfur dioxide emissions from Natural Gas Processing Plants. As a result of these NSPS, this proposal amends the Crude Oil and Natural Gas Production source category currently listed under section 111 of the Clean Air Act to include Natural Gas Transmission and Distribution, amends the existing NSPS for volatile organic compounds (VOCs) from Natural Gas Processing Plants, and proposes NSPS for stationary sources in the source categories that are not covered by the existing NSPS. In addition, this proposal addresses the residual risk and technology review conducted for two source categories in the Oil and Natural Gas sector regulated by separate National Emission Standards for Hazardous Air Pollutants (NESHAP). It also proposes standards for emission sources not currently addressed, as well as amendments to improve aspects of these NESHAP related to applicability and implementation. Finally, it addresses provisions in these NESHAP related to emissions during periods of startup, shutdown, and malfunction.

As part of the regulatory process, EPA is required to develop a regulatory impact analysis (RIA) for rules that have costs or benefits that exceed $100 million. EPA estimates the proposed NSPS will have costs that exceed $100 million, so the Agency has prepared an RIA. Because the NESHAP amendments are being proposed in the same rulemaking package (i.e., same Preamble), we have chosen to present the economic impact analysis for the proposed NESHAP amendments within the same document as the NSPS RIA.

This RIA includes an economic impact analysis and an analysis of human health and climate impacts anticipated from the proposed NSPS and NESHAP amendments. We also estimate potential impacts of the proposed NSPS on the national energy economy using the U.S. Energy Information Administration's National Energy Modeling System (NEMS). The engineering compliance costs are annualized using a 7 percent discount rate. This analysis assumes an analysis year of 2015.

Several proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOCs, a large proportion

of the averted methane emissions can be directed into natural gas production streams and sold. One emissions control option, reduced emissions well completions, also recovers saleable hydrocarbon condensates which would otherwise be lost to the environment. The revenues derived from additional natural gas and condensate recovery are expected to offset the engineering costs of implementing the NSPS in the proposed option. In the economic impact and energy economy analyses for the NSPS, we present results for three regulatory options that include the additional product recovery and the revenues we expect producers to gain from the additional product recovery.

1.2 NSPS Results

For the proposed NSPS, the key results of the RIA follow and are summarized in Table 1-1:

- **Benefits Analysis:** The proposed NSPS is anticipated to prevent significant new emissions, including 37,000 tons of hazardous air pollutants (HAPs), 540,000 tons of VOCs, and 3.4 million tons of methane. While we expect that these avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to HAPs, ozone, and particulate matter (PM), we have determined that quantification of those benefits cannot be accomplished for this rule. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, as well as additional natural gas recovery. The methane emissions reductions associated with the proposed NSPS are likely to result in significant climate co-benefits. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of carbon dioxide (CO_2), 510 tons of nitrogen oxides NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.
- **Engineering Cost Analysis:** EPA estimates the total capital cost of the proposed NSPS will be $740 million. The total annualized engineering costs of the proposed NSPS will be $740 million. When estimated revenues from additional natural gas and condensate recovery are included, the annualized engineering costs of the proposed NSPS are estimated at $-45 million, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf) and condensate price of $70/barrel. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA. The estimated engineering compliance costs that include the product recovery are sensitive to the assumption about the price of the recovered product. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. For example, $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million, given EPA estimates that 180 billion cubic feet of natural gas

will be recovered by implementing the proposed NSPS option. All estimates are in 2008 dollars.

- **Energy System Impacts:** Using the NEMS, when additional natural gas recovery is included, the analysis of energy system impacts for the proposed NSPS shows that domestic natural gas production is likely to increase slightly (about 20 billion cubic feet or 0.1 percent) and average natural gas prices to decrease slightly (about $0.04/Mcf or 0.9 percent at the wellhead for onshore production in the lower 48 states). Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.02/barrel or less than 0.1 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars.
- **Small Entity Analyses:** EPA performed a screening analysis for impacts on small entities by comparing compliance costs to revenues. For the proposed NSPS, we found that there will not be a significant impact on a substantial number of small entities (SISNOSE).
- **Employment Impacts Analysis:** EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, as well as labor associated with new reporting and recordkeeping requirements. We estimate up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NSPS is estimated at 230 full-time-equivalent employees. The annual labor requirement to comply with proposed NSPS is estimated at about 2,400 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

Table 1-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Oil and Natural Gas NSPS Regulatory Options in 2015 (millions of 2008$)[1]

	Option 1: Alternative	Option 2: Proposed[4]	Option 3: Alternative
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$19 million	-$45 million	$77 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	17,000 tons of HAPs[5]	37,000 tons of HAPs[5]	37,000 tons of HAPs[5]
	270,000 tons of VOCs	540,000 tons of VOCs	550,000 tons of VOCs
	1.6 million tons of methane[5]	3.4 million tons of methane[5]	3.4 million tons of methane[5]
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

1.3 NESHAP Amendments Results

For the proposed NESHAP amendments, the key results of the RIA follow and are summarized in Table 1-2:

- **Benefits Analysis:** The proposed NESHAP amendments are anticipated to reduce a significant amount of existing emissions, including 1,400 tons of HAPs, 9,200 tons of VOCs, and 4,900 tons of methane. Results from the residual risk assessment indicate that for existing natural gas transmission and storage, the maximum individual cancer risk decreases from 90-in-a-million before controls to 20-in-a-million after controls with benzene as the primary cancer risk driver. While we expect that these avoided emissions will result in improvements in ambient air quality and reductions in health effects associated with exposure to HAPs, ozone, and PM, we have determined that quantification of those benefits cannot be accomplished for this rule. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, and climate effects as well as additional natural gas recovery. The specific control technologies for the proposed NESHAP is anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.
- **Engineering Cost Analysis:** EPA estimates the total capital costs of the proposed NESHAP amendments to be $52 million. Total annualized engineering costs of the proposed NESHAP amendments are estimated to be $16 million. All estimates are in 2008 dollars.
- **Energy System Impacts:** We did not estimate the energy economy impacts of the proposed NESHAP amendments as the expected costs of the rule are not likely to have estimable impacts on the national energy economy.
- **Small Entity Analyses:** EPA performed a screening analysis for impacts on small entities by comparing compliance costs to revenues. For the proposed NESHAP amendments, we found that there will not be a significant impact on a substantial number of small entities (SISNOSE).
- **Employment Impacts Analysis:** EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, as well as labor associated with new reporting and recordkeeping requirements. We estimate up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NESHAP Amendments is estimated at 120 full-time-equivalent employees. The annual labor requirement to comply with proposed NESHAP Amendments is estimated at about 102 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

- **Break-Even Analysis:** A break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health benefits, ecosystem and climate co-benefits from the reductions in VOC and methane emissions are assumed to be zero. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the benefits to exceed the costs. Previous assessments have shown that the $PM_{2.5}$ benefits associated with reducing VOC emissions were valued at $280 to $7,000 per ton of VOC emissions reduced in specific urban areas. Previous assessments have shown that the $PM_{2.5}$ benefits associated with reducing VOC emissions were valued at $280 to $7,000 per ton of VOC emissions reduced in specific urban areas, ozone benefits valued at $240 to $1,000 per ton of VOC emissions reduced, and climate co-benefits valued at $110 to $1,400 per short ton of methane reduced. All estimates are in 2008 dollars.

Table 1-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NESHAP in 2015 (millions of 2008$)[1]

	Option 1: Proposed (Floor)
Total Monetized Benefits[2]	N/A
Total Costs[3]	$16 million
Net Benefits	N/A
Non-monetized Benefits	1,400 tons of HAPs
	9,200 tons of VOCs[4]
	4,900 tons of methane[4]
	Health effects of HAP exposure
	Health effects of $PM_{2.5}$ and ozone exposure[4]
	Visibility impairment[4]
	Vegetation effects[4]
	Climate effects[4]

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and PM as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NESHAP are anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] Reduced exposure to VOC emissions, PM2.5 and ozone exposure, visibility and vegetation effects, and climate effects are co-benefits.

1.4 Organization of this Report

The remainder of this report details the methodology and the results of the RIA. Section 2 presents the industry profile of the oil and natural gas industry. Section 3 describes the emissions and engineering cost analysis. Section 4 presents the benefits analysis. Section 5 presents statutory and executive order analyses. Section 6 presents a comparison of benefits and costs. Section 7 presents energy system impact, employment impact, and small business impact analyses.

2 INDUSTRY PROFILE

2.1 Introduction

The oil and natural gas industry includes the following five segments: drilling and extraction, processing, transportation, refining, and marketing. The Oil and Natural Gas NSPS and NESHAP amendments propose controls for the oil and natural gas products and processes of the drilling and extraction of crude oil and natural gas, natural gas processing, and natural gas transportation segments.

Most crude oil and natural gas production facilities are classified under NAICS 211: Crude Petroleum and Natural Gas Extraction (211111) and Natural Gas Liquid Extraction (211112). The drilling of oil and natural gas wells is included in NAICS 213111. Most natural gas transmission and storage facilities are classified under NAICS 486210—Pipeline Transportation of Natural Gas. While other NAICS (213112—Support Activities for Oil and Gas Operations, 221210—Natural Gas Distribution, 486110—Pipeline Transportation of Crude Oil, and 541360—Geophysical Surveying and Mapping Services) are often included in the oil and natural gas sector, these are not discussed in detail in the Industry Profile because they are not directly affected by the proposed NSPS and NESHAP amendments.

The outputs of the oil and natural gas industry are inputs for larger production processes of gas, energy, and petroleum products. As of 2009, the Energy Information Administration (EIA) estimates that about 526,000 producing oil wells and 493,000 producing natural gas wells operated in the United States. Domestic dry natural gas production was 20.5 trillion cubic feet (tcf) in 2009, the highest production level since 1970. The leading five natural gas producing states are Texas, Alaska, Wyoming, Oklahoma, and New Mexico. Domestic crude oil production in 2009 was 1,938 million barrels (bbl). The leading five crude oil producing states are Texas, Alaska, California, Oklahoma, and New Mexico.

The Industry Profile provides a brief introduction to the components of the oil and natural gas industry that are relevant to the proposed NSPS and NESHAP Amendments. The purpose is to give the reader a general understanding of the geophysical, engineering, and economic aspects of the industry that are addressed in subsequent economic analysis in this RIA. The Industry Profile relies heavily on background material from the U.S. EPA's "Economic Analysis of Air

Pollution Regulations: Oil and Natural Gas Production" (1996) and the U.S. EPA's "Sector Notebook Project: Profile of the Oil and Gas Extraction Industry" (2000).

2.2 Products of the Crude Oil and Natural Gas Industry

Each producing crude oil and natural gas field has its own unique properties. The composition of the crude oil and natural gas and reservoir characteristics are likely to be different from that of any other reservoir.

2.2.1 Crude Oil

Crude oil can be broadly classified as paraffinic, naphthenic (or asphalt-based), or intermediate. Generally, paraffinic crudes are used in the manufacture of lube oils and kerosene. Paraffinic crudes have a high concentration of straight chain hydrocarbons and are relatively low in sulfur compounds. Naphthenic crudes are generally used in the manufacture of gasolines and asphalt and have a high concentration of olefin and aromatic hydrocarbons. Naphthenic crudes may contain a high concentration of sulfur compounds. Intermediate crudes are those that are not classified in either of the above categories.

Another classification measure of crude oil and other hydrocarbons is by API gravity. API gravity is a weight per unit volume measure of a hydrocarbon liquid as determined by a method recommended by the American Petroleum Institute (API). A heavy or paraffinic crude oil is typically one with API gravity of 20^{o} or less, while a light or naphthenic crude oil, which typically flows freely at atmospheric conditions, usually has API gravity in the range of the high 30's to the low 40's.

Crude oils recovered in the production phase of the petroleum industry may be referred to as live crudes. Live crudes contain entrained or dissolved gases which may be released during processing or storage. Dead crudes are those that have gone through various separation and storage phases and contain little, if any, entrained or dissolved gases.

2.2.2 Natural Gas

Natural gas is a mixture of hydrocarbons and varying quantities of non-hydrocarbons that exists in a gaseous phase or in solution with crude oil or other hydrocarbon liquids in natural

underground reservoirs. Natural gas may contain contaminants, such as hydrogen sulfide (H_2S), CO_2, mercaptans, and entrained solids.

Natural gas may be classified as wet gas or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons. Dry gas is either natural gas whose water content has been reduced through dehydration or natural gas that contains little or no recoverable liquid hydrocarbons.

Natural gas streams that contain threshold concentrations of H_2S are classified as sour gases. Those with threshold concentrations of CO_2 are classified as acid gases. The process by which these two contaminants are removed from the natural gas stream is called sweetening. The most common sweetening method is amine treating. Sour gas contains a H_2S concentration of greater than 0.25 grain per 100 standard cubic feet, along with the presence of CO_2. Concentrations of H_2S and CO_2, along with organic sulfur compounds, vary widely among sour gases. A majority total onshore natural gas production and nearly all of offshore natural gas production is classified as sweet.

2.2.3 Condensates

Condensates are hydrocarbons in a gaseous state under reservoir conditions, but become liquid in either the wellbore or the production process. Condensates, including volatile oils, typically have an API gravity of 40^o or more. In addition, condensates may include hydrocarbon liquids recovered from gaseous streams from various oil and natural gas production or natural gas transmission and storage processes and operations.

2.2.4 Other Recovered Hydrocarbons

Various hydrocarbons may be recovered through the processing of the extracted hydrocarbon streams. These hydrocarbons include mixed natural gas liquids (NGL), natural gasoline, propane, butane, and liquefied petroleum gas (LPG).

2.2.5 Produced Water

Produced water is the water recovered from a production well. Produced water is separated from the extracted hydrocarbon streams in various production processes and operations.

2.3 Oil and Natural Gas Production Processes

2.3.1 Exploration and Drilling

Exploration involves the search for rock formations associated with oil or natural gas deposits and involves geophysical prospecting and/or exploratory drilling. Well development occurs after exploration has located an economically recoverable field and involves the construction of one or more wells from the beginning (called spudding) to either abandonment if no hydrocarbons are found or to well completion if hydrocarbons are found in sufficient quantities.

After the site of a well has been located, drilling commences. A well bore is created by using a rotary drill to drill into the ground. As the well bore gets deeper sections of drill pipe are added. A mix of fluids called drilling mud is released down into the drill pipe then up the walls of the well bore, which removes drill cuttings by taking them to the surface. The weight of the mud prevents high-pressure reservoir fluids from pushing their way out ("blowing out"). The well bore is cased in with telescoping steel piping during drilling to avoid its collapse and to prevent water infiltration into the well and to prevent crude oil and natural gas from contaminating the water table. The steel pipe is cemented by filling the gap between the steel casing and the wellbore with cement.

Horizontal drilling technology has been available since the 1950s. Horizontal drilling facilitates the construction of horizontal wells by allowing for the well bore to run horizontally underground, increasing the surface area of contact between the reservoir and the well bore so that more oil or natural gas can move into the well. Horizontal wells are particularly useful in unconventional gas extraction where the gas is not concentrated in a reservoir. Recent advances have made it possible to steer the drill in different directions (directional drilling) from the

surface without stopping the drill to switch directions and allowing for a more controlled and precise drilling trajectory.

Hydraulic fracturing (also referred to as "fracking") has been performed since the 1940s (U.S. DOE, 2009). Hydraulic fracturing involves pumping fluids into the well under very high pressures in order to fracture the formation containing the resource. Proppant is a mix of sand and other materials that is pumped down to hold the fractures open to secure gas flow from the formation (U.S. EPA, 2004).

2.3.2 Production

Production is the process of extracting the hydrocarbons and separating the mixture of liquid hydrocarbons, gas, water, and solids, removing the constituents that are non-saleable, and selling the liquid hydrocarbons and gas. The major activities of crude oil and natural gas production are bringing the fluid to the surface, separating the liquid and gas components, and removing impurities.

Oil and natural gas are found in the pores of rocks and sand (Hyne, 2001). In a conventional source, the oil and natural gas have been pushed out of these pores by water and moved until an impermeable surface had been reached. Because the oil and natural gas can travel no further, the liquids and gases accumulate in a reservoir. Where oil and gas are associated, a gas cap forms above the oil. Natural gas is extracted from a well either because it is associated with oil in an oil well or from a pure natural gas reservoir. Once a well has been drilled to reach the reservoir, the oil and gas can be extracted in different ways depending on the well pressure (Hyne, 2001).

Frequently, oil and natural gas are produced from the same reservoir. As wells deplete the reservoirs into which they are drilled, the gas to oil ratio increases (as does the ratio of water to hydrocarbons). This increase of gas over oil occurs because natural gas usually is in the top of the oil formation, while the well usually is drilled into the bottom portion to recover most of the liquid. Production sites often handle crude oil and natural gas from more than one well (Hyne, 2001).

Well pressure is required to move the resource up from the well to the surface. During **primary extraction,** pressure from the well itself drives the resource out of the well directly. Well pressure depletes during this process. Typically, about 30 to 35 percent of the resource in the reservoir is extracted this way (Hyne, 2001). The amount extracted depends on the specific well characteristics (such as permeability and oil viscosity). Lacking enough pressure for the resource to surface, gas or water is injected into the well to increase the well pressure and force the resource out (**secondary** or **improved oil recovery).** Finally, **in tertiary extraction** or **enhanced recovery,** gas, chemicals or steam are injected into the well. This can result in recovering up to 60 percent of the original amount of oil in the reservoir (Hyne, 2001).

In contrast to conventional sources, unconventional oil and gas are trapped in rock or sand or, in the case of oil, are found in rock as a chemical substance that requires a further chemical transformation to become oil (U.S. DOE, 2009). Therefore, the resource does not move into a reservoir as in the case with a conventional source. Mining, induced pressure, or heat is required to release the resource. The specific type of extraction method needed depends on the type of formation where the resource is located. Unconventional natural gas resource types relevant for this proposal include:

- **Shale Natural Gas:** Shale natural gas comes from sediments of clay mixed with organic matter. These sediments form low permeability shale rock formations that do not allow the gas to move. To release the gas, the rock must be fragmented, making the extraction process more complex than it is for conventional gas extraction. Shale gas can be extracted by drilling either vertically or horizontally, and breaking the rock using hydraulic fracturing (U.S. DOE, 2009).

- **Tight Sands Natural Gas:** Reservoirs are composed of low-porosity sandstones and carbonate into which natural gas has migrated from other sources. Extraction of the natural gas from tight gas reservoirs is often performed using horizontal wells. Hydraulic fracturing is often used in tight sands (U.S. DOE, 2009).

- **Coalbed Methane:** Natural gas is present in a coal bed due to the activity of microbes in the coal or from alterations of the coal through temperature changes. Horizontal drilling

is used but given that coalbed methane reservoirs are frequently associated with underground water reservoirs, hydraulic fracturing is often restricted (Andrews, 2009).

2.3.3 Natural Gas Processing

Natural gas conditioning is the process of removing impurities from the gas stream so that it is of sufficient quality to pass through transportation systems and used by final consumers. Conditioning is not always required. Natural gas from some formations emerges from the well sufficiently pure that it can be sent directly to the pipeline. As the natural gas is separated from the liquid components, it may contain impurities that pose potential hazards or other problems.

The most significant impurity is H_2S, which may or may not be contained in natural gas. H_2S is toxic (and potentially fatal at certain concentrations) to humans and is corrosive for pipes. It is therefore desirable to remove H_2S as soon as possible in the conditioning process.

Another concern is that posed by water vapor. At high pressures, water can react with components in the gas to form gas hydrates, which are solids that can clog pipes, valves, and gauges, especially at cold temperatures (Manning and Thompson, 1991). Nitrogen and other gases may also be mixed with the natural gas in the subsurface. These other gases must be separated from the methane prior to sale. High vapor pressure hydrocarbons that are liquids at surface temperature and pressure (benzene, toluene, ethylbenzene, and xylene, or BTEX) are removed and processed separately.

Dehydration removes water from the gas stream. Three main approaches toward dehydration are the use of a liquid or solid desiccant, and refrigeration. When using a liquid desiccant, the gas is exposed to a glycol that absorbs the water. The water can be evaporated from the glycol by a process called heat regeneration. The glycol can then be reused. Solid desiccants, often materials called molecular sieves, are crystals with high surface areas that attract the water molecules. The solids can be regenerated simply by heating them above the boiling point of water. Finally, particularly for gas extracted from deep, hot wells, simply cooling the gas to a temperature below the condensation point of water can remove enough water to transport the gas. Of the three approaches mentioned above, glycol dehydration is the most common when processing at or near the well.

Sweetening is the procedure in which H_2S and sometimes CO_2 are removed from the gas stream. The most common method is amine treatment. In this process, the gas stream is exposed to an amine solution, which will react with the H_2S and separate them from the natural gas. The contaminant gas solution is then heated, thereby separating the gases and regenerating the amine. The sulfur gas may be disposed of by flaring, incinerating, or when a market exists, sending it to a sulfur-recovery facility to generate elemental sulfur as a salable product.

2.3.4 Natural Gas Transmission and Distribution

After processing, natural gas enters a network of compressor stations, high-pressure transmission pipelines, and often-underground storage sites. Compressor stations are any facility which supplies energy to move natural gas at increased pressure in transmission pipelines or into underground storage. Typically, compressor stations are located at intervals along a transmission pipeline to maintain desired pressure for natural gas transport. These stations will use either large internal combustion engines or gas turbines as prime movers to provide the necessary horsepower to maintain system pressure. Underground storage facilities are subsurface facilities utilized for storing natural gas which has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at underground storage facilities include compression and dehydration.

2.4 Reserves and Markets

Crude oil and natural gas have historically served two separate and distinct markets. Oil is an international commodity, transported and consumed throughout the world. Natural gas, on the other hand, has historically been consumed close to where it is produced. However, as pipeline infrastructure and LNG trade expand, natural gas is increasingly a national and international commodity. The following subsections provide historical and forecast data on the U.S. reserves, production, consumption, and foreign trade of crude oil and natural gas.

2.4.1 Domestic Proved Reserves

Table 2-1 shows crude oil and natural gas proved reserves, inferred reserves, and undiscovered and total technically recoverable resources as of 2007. According to EIA[1], these concepts are defined as:

- **Proved reserves:** estimated quantities of energy sources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.

- **Inferred reserves:** the estimate of total volume recovery from known crude oil or natural gas reservoirs or aggregation of such reservoirs is expected to increase during the time between discovery and permanent abandonment.

- **Technically recoverable:** resources that are producible using current technology without reference to the economic viability of production.

The sum of proved reserves, inferred reserves, and undiscovered technically recoverable resources equal the total technically recoverable resources. As seen in Table 2-1, as of 2007, proved domestic crude oil reserves accounted for about 12 percent of the totally technically recoverable crude oil resources.

[1] U.S. Department of Energy, Energy Information Administration, Glossary of Terms <http://www.eia.doe.gov/glossary/index.cfm?id=P> Accessed 12/21/2010.

Table 2-1 Technically Recoverable Crude Oil and Natural Gas Resource Estimates, 2007

Region	Proved Reserves	Inferred Reserves	Undiscovered Technically Recoverable Resources	Total Technically Recoverable Resources
Crude Oil and Lease Condensate (billion bbl)				
48 States Onshore	14.2	48.3	25.3	87.8
48 States Offshore	4.4	10.3	47.2	61.9
Alaska	4.2	2.1	42.0	48.3
Total U.S.	22.8	60.7	114.5	198.0
Dry Natural Gas (tcf)				
Conventionally Reservoired Fields	194.0	671.3	760.4	1625.7
48 States Onshore Non-Associated Gas	149.0	595.9	144.1	889.0
48 States Offshore Non-Associated Gas	12.4	50.7	233.0	296.0
Associated-Dissolved Gas	20.7		117.2	137.9
Alaska	11.9	24.8	266.1	302.8
Shale Gas and Coalbed Methane	43.7	385	64.2	493.0
Total U.S.	237.7	1056.3	824.6	2118.7

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Inferred reserves for associated-dissolved natural gas are included in "Undiscovered Technically Recoverable Resources." Totals may not sum due to independent rounding.

Proved natural gas reserves accounted for about 11 percent of the totally technically recoverable natural gas resources. Significant proportions of these reserves exist in Alaska and offshore areas.

Table 2-2 and Figure 2-1 show trends in crude oil and natural gas production and reserves from 1990 to 2008. In Table 2-2, proved ultimate recovery equals the sum of cumulative production and proved reserves. While crude oil and natural gas are nonrenewable resources, the table shows that proved ultimate recovery rises over time as new discoveries become economically accessible. Reserves growth and decline is also partly a function of exploration activities, which are correlated with oil and natural gas prices. For example, when oil prices are high there is more of an incentive to use secondary and tertiary recovery, as well as to develop unconventional sources.

Table 2-2 Crude Oil and Natural Gas Cumulative Domestic Production, Proved Reserves, and Proved Ultimate Recovery, 1977-2008

	Crude Oil and Lease Condensate (million bbl)			Dry Natural Gas (bcf)		
Year	Cumulative Production	Proved Reserves	Proved Ultimate Recovery	Cumulative Production	Proved Reserves	Proved Ultimate Recovery
1990	158,175	27,556	185,731	744,546	169,346	913,892
1991	160,882	25,926	186,808	762,244	167,062	929,306
1992	163,507	24,971	188,478	780,084	165,015	945,099
1993	166,006	24,149	190,155	798,179	162,415	960,594
1994	168,438	23,604	192,042	817,000	163,837	980,837
1995	170,832	23,548	194,380	835,599	165,146	1,000,745
1996	173,198	23,324	196,522	854,453	166,474	1,020,927
1997	175,553	23,887	199,440	873,355	167,223	1,040,578
1998	177,835	22,370	200,205	892,379	164,041	1,056,420
1999	179,981	23,168	203,149	911,211	167,406	1,078,617
2000	182,112	23,517	205,629	930,393	177,427	1,107,820
2001	184,230	23,844	208,074	950,009	183,460	1,133,469
2002	186,327	24,023	210,350	968,937	186,946	1,155,883
2003	188,400	23,106	211,506	988,036	189,044	1,177,080
2004	190,383	22,592	212,975	1,006,564	192,513	1,199,077
2005	192,273	23,019	215,292	1,024,638	204,385	1,229,023
2006	194,135	22,131	216,266	1,043,114	211,085	1,254,199
2007	196,079	22,812	218,891	1,062,203	237,726	1,299,929
2008	197,987	20,554	218,541	1,082,489	244,656	1,327,145

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**

However, annual production as a percentage of proved reserves has declined over time for both crude oil and natural gas, from above 10 percent in the early 1990s to 8 to 9 percent from 2006 to 2008 for crude oil and from above 11 percent during the 1990s to about 8 percent from 2008 to 2008 for natural gas.

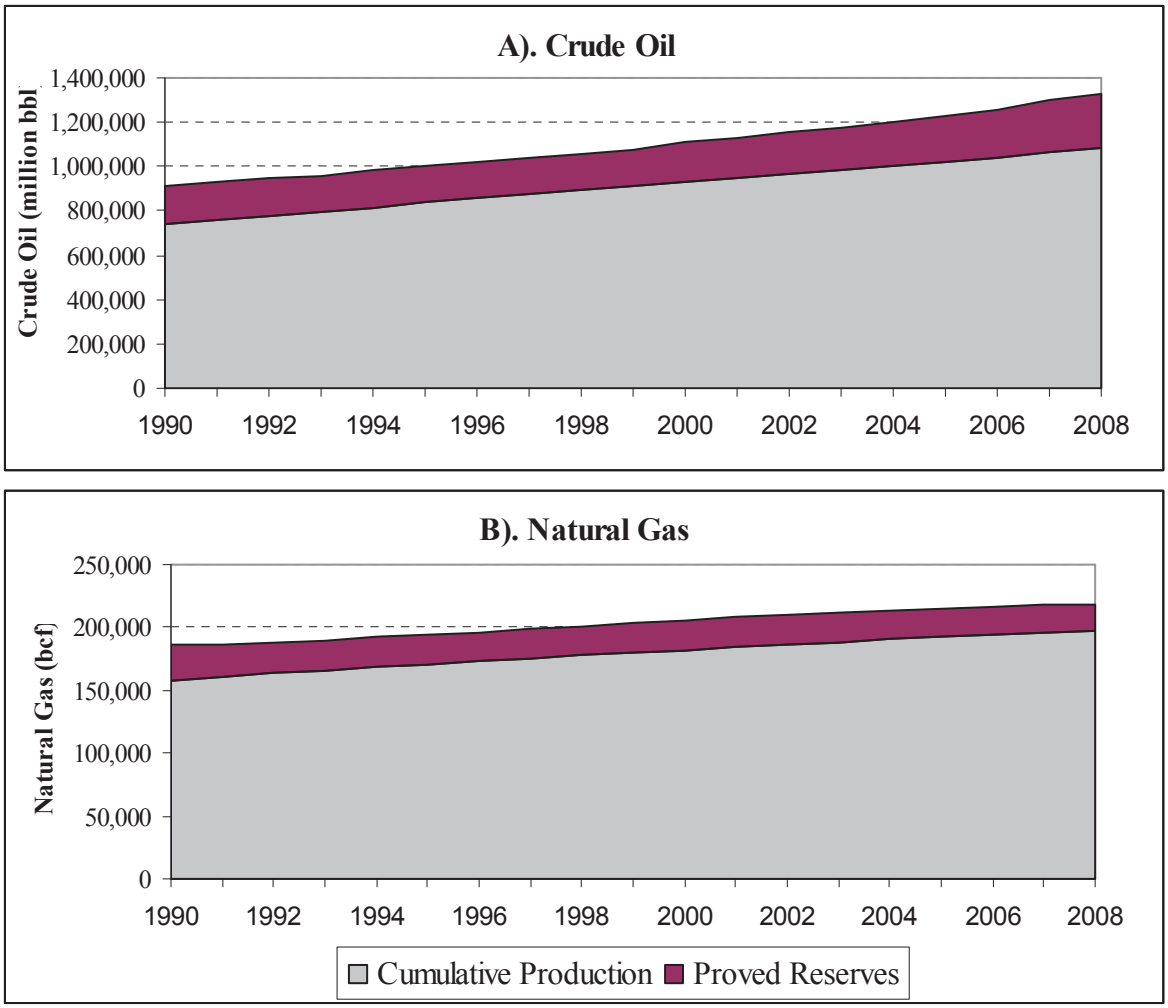


Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2008. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2008

Table 2-3 presents the U.S. proved reserves of crude oil and natural gas by state or producing area as of 2008. Four areas currently account for 77 percent of the U.S. total proved reserves of crude oil, led by Texas and followed by U.S. Federal Offshore, Alaska, and California. The top five states (Texas, Wyoming, Colorado, Oklahoma, and New Mexico) account for about 69 percent of the U.S. total proved reserves of natural gas.

Table 2-3 Crude Oil and Dry Natural Gas Proved Reserves by State, 2008

State/Region	Crude Oil (million bbls)	Dry Natural Gas (bcf)	Crude Oil (percent of total)	Dry Natural Gas (percent of total)
Alaska	3,507	7,699	18.3	3.1
Alabama	38	3,290	0.2	1.3
Arkansas	30	5,626	0.2	2.3
California	2,705	2,406	14.1	1.0
Colorado	288	23,302	1.5	9.5
Florida	3	1	0.0	0.0
Illinois	54	0	0.3	0.0
Indiana	15	0	0.1	0.0
Kansas	243	3,557	1.3	1.5
Kentucky	17	2,714	0.1	1.1
Louisiana	388	11,573	2.0	4.7
Michigan	48	3,174	0.3	1.3
Mississippi	249	1,030	1.3	0.4
Montana	321	1,000	1.7	0.4
Nebraska	8	0	0.0	0.0
New Mexico	654	16,285	3.4	6.7
New York	0	389	0.0	0.2
North Dakota	573	541	3.0	0.2
Ohio	38	985	0.2	0.4
Oklahoma	581	20,845	3.0	8.5
Pennsylvania	14	3,577	0.1	1.5
Texas	4,555	77,546	23.8	31.7
Utah	286	6,643	1.5	2.7
Virginia	0	2,378	0.0	1.0
West Virginia	23	5,136	0.1	2.1
Wyoming	556	31,143	2.9	12.7
Miscellaneous States	24	270	0.1	0.1
U.S. Federal Offshore	3,903	13,546	20.4	5.5
Total Proved Reserves	**19,121**	**244,656**	100.0	100.0

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Totals may not sum due to independent rounding.

2.4.2 Domestic Production

Domestic oil production is currently in a state of decline that began in 1970. Table 2-4 shows U.S. production in 2009 at 1938 million bbl per year, the highest level since 2004. However, annual domestic production of crude oil has dropped by almost 750 million bbl since 1990.

Table 2-4 Crude Oil Domestic Production, Wells, Well Productivity, and U.S. Average First Purchase Price

Year	Total Production (million bbl)	Producing Wells (1000s)	Avg. Well Productivity (bbl/well)	U.S. Average First Purchase Price/Barrel (2005 dollars)
1990	2,685	602	4,460	27.74
1991	2,707	614	4,409	22.12
1992	2,625	594	4,419	20.89
1993	2,499	584	4,279	18.22
1994	2,431	582	4,178	16.51
1995	2,394	574	4,171	17.93
1996	2,366	574	4,122	22.22
1997	2,355	573	4,110	20.38
1998	2,282	562	4,060	12.71
1999	2,147	546	3,932	17.93
2000	2,131	534	3,990	30.14
2001	2,118	530	3,995	24.09
2002	2,097	529	3,964	24.44
2003	2,073	513	4,042	29.29
2004	1,983	510	3,889	38.00
2005	1,890	498	3,795	50.28
2006	1,862	497	3,747	57.81
2007	1,848	500	3,697	62.63
2008	1,812	526	3,445	86.69
2009	1,938	526	3,685	51.37*

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**

First purchase price represents the average price at the lease or wellhead at which domestic crude is purchased. * 2009 Oil price is preliminary

Average well productivity has also decreased since 1990 (Table 2-4 and Figure 2-2). These production and productivity decreases are in spite of the fact that average first purchase prices have shown a generally increasing trend. The exception to this general trend occurred in 2008 and 2009 when the real price increased up to 86 dollars per barrel and production in 2009 increased to almost 2 million bbl of oil.

Annual production of natural gas from natural gas wells has increased nearly 3000 bcf from the 1990 to 2009 (Table 2-5). Natural gas extracted from crude oil wells (associated natural gas) has remained more or less constant for the last twenty years. Coalbed methane has become a significant component of overall gas withdrawals in recent years.

Table 2-5 Natural Gas Production and Well Productivity, 1990-2009

	Natural Gas Gross Withdrawals (bcf)					Natural Gas Well Productivity	
Year	Natural Gas Wells	Crude Oil Wells	Coalbed Methane Wells	Total	Dry Gas Production*	Producing Wells (no.)	Avg. Productivity per Well (MMcf)
1990	16,054	5,469	NA	21,523	17,810	269,100	59.657
1991	16,018	5,732	NA	21,750	17,698	276,337	57.964
1992	16,165	5,967	NA	22,132	17,840	275,414	58.693
1993	16,691	6,035	NA	22,726	18,095	282,152	59.157
1994	17,351	6,230	NA	23,581	18,821	291,773	59.468
1995	17,282	6,462	NA	23,744	18,599	298,541	57.888
1996	17,737	6,376	NA	24,114	18,854	301,811	58.770
1997	17,844	6,369	NA	24,213	18,902	310,971	57.382
1998	17,729	6,380	NA	24,108	19,024	316,929	55.938
1999	17,590	6,233	NA	23,823	18,832	302,421	58.165
2000	17,726	6,448	NA	24,174	19,182	341,678	51.879
2001	18,129	6,371	NA	24,501	19,616	373,304	48.565
2002	17,795	6,146	NA	23,941	18,928	387,772	45.890
2003	17,882	6,237	NA	24,119	19,099	393,327	45.463
2004	17,885	6,084	NA	23,970	18,591	406,147	44.036
2005	17,472	5,985	NA	23,457	18,051	425,887	41.025
2006	17,996	5,539	NA	23,535	18,504	440,516	40.851
2007	17,065	5,818	1,780	24,664	19,266	452,945	37.676
2008	18,011	5,845	1,898	25,754	20,286	478,562	37.636
2009	18,881	5,186	2,110	26,177	20,955	495,697	38.089

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.**
*Dry gas production is gas production after accounting for gas used repressurizing wells, the removal of nonhydrocarbon gases, vented and flared gas, and gas used as fuel during the production process.

The number of wells producing natural gas wells has nearly doubled between 1990 and 2009 (Figure 2-2). While the number of producing wells has increased overall, average well productivity has declined, despite improvements in exploration and gas well stimulation technologies.

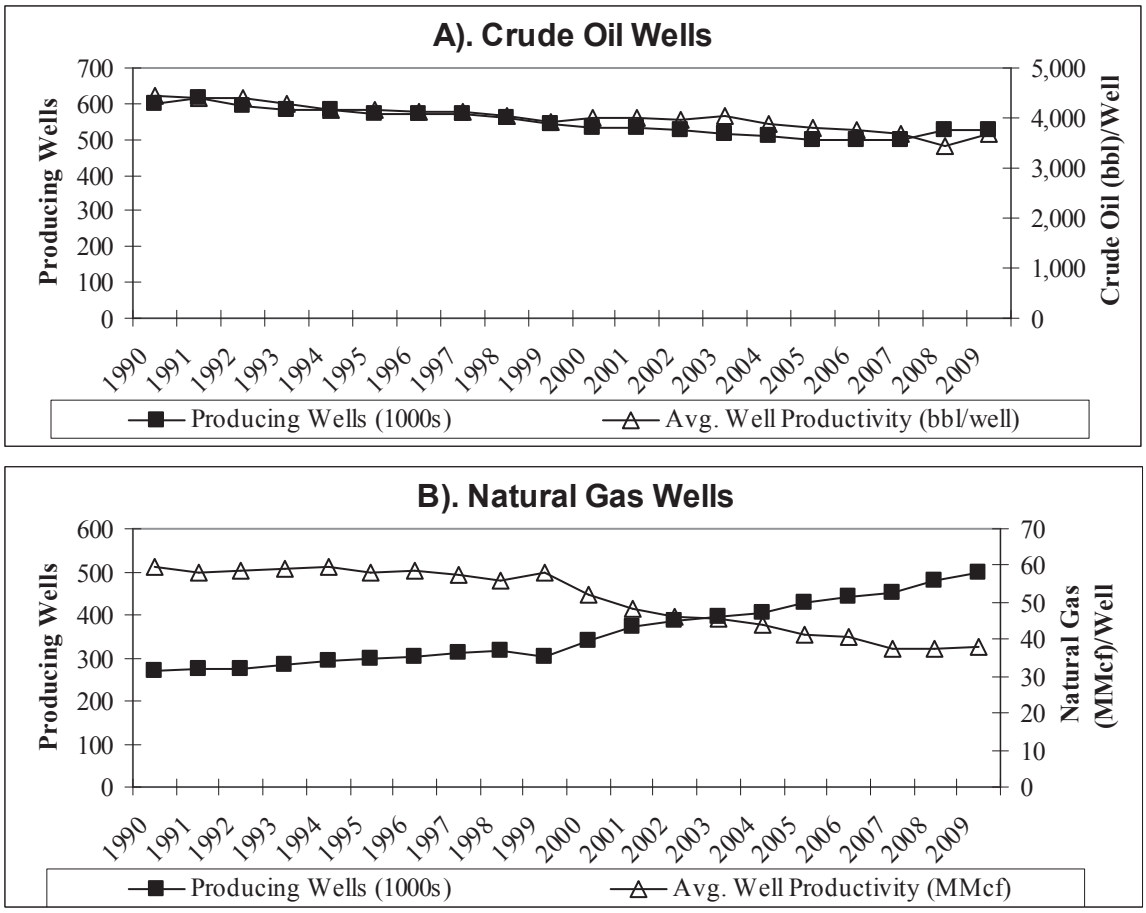


Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2009. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2009.

Domestic exploration and development for oil has continued during the last two decades. From 2002 to 2009, crude oil well drilling showed significant increases, although the 1992-2001 period showed relatively low levels of crude drilling activity compared to periods before and after (Table 2-6). The drop in 2009 showed a departure from this trend, likely due to the recession experienced in the U.S.

Meanwhile, natural gas drilling has increased significantly during the 1990-2009 period. Like crude oil drilling, 2009 saw a relatively low level of natural gas drillings. The success rate of wells (producing wells versus dry wells) has also increased gradually over time from 75 percent in 1990, to 86 percent in 2000, to 90 percent in 2009 (Table 2-6). The increasing success rate reflects improvements in exploration technology, as well as technological improvements in

well drilling and completion. Similarly, well average depth has also increased by during this period (Table 2-6).

Table 2-6 Crude Oil and Natural Gas Exploratory and Development Wells and Average Depth, 1990-2009

	Wells Drilled					
Year	Crude Oil	Natural Gas	Dry Holes	Total	Successful Wells (percent)	Average Depth (ft)
1990	12,800	11,227	8,237	32,264	75	4,841
1991	12,542	9,768	7,476	29,786	75	4,872
1992	9,379	8,149	5,857	23,385	75	5,138
1993	8,828	9,829	6,093	24,750	75	5,407
1994	7,334	9,358	5,092	21,784	77	5,736
1995	8,230	8,081	4,813	21,124	77	5,560
1996	8,819	9,015	4,890	22,724	79	5,573
1997	11,189	11,494	5,874	28,557	79	5,664
1998	7,659	11,613	4,763	24,035	80	5,722
1999	4,759	11,979	3,554	20,292	83	5,070
2000	8,089	16,986	4,134	29,209	86	4,942
2001	8,880	22,033	4,564	35,477	87	5,077
2002	6,762	17,297	3,728	27,787	87	5,223
2003	8,104	20,685	3,970	32,759	88	5,418
2004	8,764	24,112	4,053	36,929	89	5,534
2005E	10,696	28,500	4,656	43,852	89	5,486
2006E	13,289	32,878	5,183	51,350	90	5,537
2007E	13,564	33,132	5,121	51,817	90	5,959
2008E	17,370	34,118	5,726	57,214	90	6,202
2009E	13,175	19,153	3,537	35,865	90	6,108

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** Values for 2005-2009 are estimates.

Produced water is an important byproduct of the oil and natural gas industry, as management, including reuse and recycling, of produced water can be costly and challenging. Texas, California, Wyoming, Oklahoma, and Kansas were the top five states in terms of produced water volumes in 2007 (Table 2-7). These estimates do not include estimates of flowback water from hydraulic fracturing activities (ANL 2009).

Table 2-7 U.S. Onshore and Offshore Oil, Gas, and Produced Water Generation, 2007

State	Crude Oil (1000 bbl)	Total Gas (bcf)	Produced Water (1000 bbl)	Total Oil and Natural Gas (1000 bbls oil equivalent)	Barrels Produced Water per Barrel Oil Equivalent
Alabama	5,028	285	119,004	55,758	2.13
Alaska	263,595	3,498	801,336	886,239	0.90
Arizona	43	1	68	221	0.31
Arkansas	6,103	272	166,011	54,519	3.05
California	244,000	312	2,552,194	299,536	8.52
Colorado	2,375	1,288	383,846	231,639	1.66
Florida	2,078	2	50,296	2,434	20.66
Illinois	3,202	no data	136,872	3,202	42.75
Indiana	1,727	4	40,200	2,439	16.48
Kansas	36,612	371	1,244,329	102,650	12.12
Kentucky	3,572	95	24,607	20,482	1.20
Louisiana	52,495	1,382	1,149,643	298,491	3.85
Michigan	5,180	168	114,580	35,084	3.27
Mississippi	20,027	97	330,730	37,293	8.87
Missouri	80	no data	1,613	80	20.16
Montana	34,749	95	182,266	51,659	3.53
Nebraska	2,335	1	49,312	2,513	19.62
Nevada	408	0	6,785	408	16.63
New Mexico	59,138	1,526	665,685	330,766	2.01
New York	378	55	649	10,168	0.06
North Dakota	44,543	71	134,991	57,181	2.36
Ohio	5,422	86	6,940	20,730	0.33
Oklahoma	60,760	1,643	2,195,180	353,214	6.21
Pennsylvania	1,537	172	3,912	32,153	0.12
South Dakota	1,665	12	4,186	3,801	1.10
Tennessee	350	1	2,263	528	4.29
Texas	342,087	6,878	7,376,913	1,566,371	4.71
Utah	19,520	385	148,579	88,050	1.69
Virginia	19	112	1,562	19,955	0.08
West Virginia	679	225	8,337	40,729	0.20
Wyoming	54,052	2,253	2,355,671	455,086	5.18
State Total	***1,273,759***	***21,290***	***20,258,560***	***5,063,379***	***4.00***
Federal Offshore	467,180	2,787	587,353	963,266	0.61
Tribal Lands	9,513	297	149,261	62,379	2.39
Federal Total	***476,693***	***3,084***	***736,614***	***1,025,645***	***0.72***
U.S. Total	**1,750,452**	**24,374**	**20,995,174**	**6,089,024**	**3.45**

Source: Argonne National Laboratory and Department of Energy (2009). Natural gas production converted to barrels oil equivalent to facilitate comparison using the conversion of 0.178 barrels of crude oil equals 1000 cubic feet natural gas. Totals may not sum due to independent rounding.

As can be seen in Table 2-7, the amount of water produced is not necessarily correlated with the ratio of water produced to the volume of oil or natural gas produced. Texas, Alaska and Wyoming were the three largest producers in barrels of oil equivalent (boe) terms, but had relatively low rates of water production compared to more Midwestern states, such Illinois, Missouri, Indiana, and Kansas.

Figure 2-3 shows the distribution of produced water management practices in 2007.

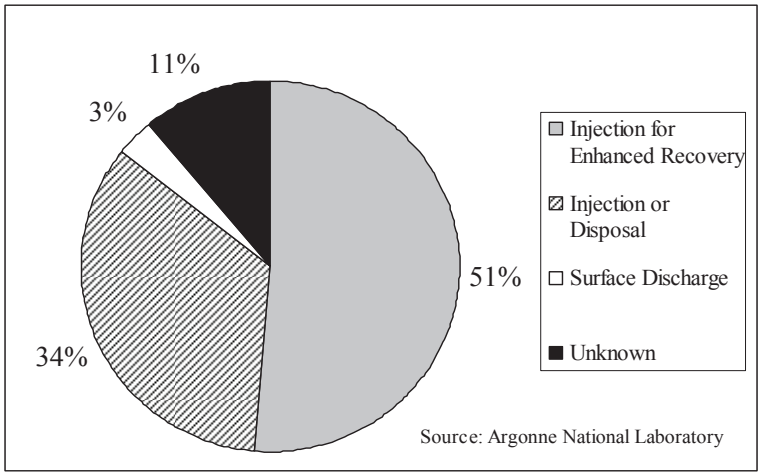


Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007

More than half of the water produced (51 percent) was re-injected to enhance resource recovery through maintaining reservoir pressure or hydraulically pushing oil from the reservoir. Another third (34 percent) was injected, typically into wells whose primary purpose is to sequester produced water. A small percentage (three percent) is discharged into surface water when it meets water quality criteria. The destination of the remaining produced water (11 percent, the difference between the total managed and total generated) is uncertain (ANL, 2009).

The movement of crude oil and natural gas primarily takes place via pipelines. Total crude oil pipeline mileage has decreased during the 1990-2008 period (Table 2-8), appearing to follow the downward supply trend shown in Table 2-4. While exhibiting some variation, pipeline mileage transporting refined products remained relatively constant.

Table 2-8 U.S. Oil and Natural Gas Pipeline Mileage, 1990-2008

	Oil Pipelines			Natural Gas Pipelines			
Year	Crude Lines	Product Lines	Total	Distribution Mains	Transmission Pipelines	Gathering Lines	Total
1990	118,805	89,947	208,752	945,964	291,990	32,420	1,270,374
1991	115,860	87,968	203,828	890,876	293,862	32,713	1,217,451
1992	110,651	85,894	196,545	891,984	291,468	32,629	1,216,081
1993	107,246	86,734	193,980	951,750	293,263	32,056	1,277,069
1994	103,277	87,073	190,350	1,002,669	301,545	31,316	1,335,530
1995	97,029	84,883	181,912	1,003,798	296,947	30,931	1,331,676
1996	92,610	84,925	177,535	992,860	292,186	29,617	1,314,663
1997	91,523	88,350	179,873	1,002,942	294,370	34,463	1,331,775
1998	87,663	90,985	178,648	1,040,765	302,714	29,165	1,372,644
1999	86,369	91,094	177,463	1,035,946	296,114	32,276	1,364,336
2000	85,480	91,516	176,996	1,050,802	298,957	27,561	1,377,320
2001	52,386	85,214	154,877	1,101,485	290,456	21,614	1,413,555
2002	52,854	80,551	149,619	1,136,479	303,541	22,559	1,462,579
2003	50,149	75,565	139,901	1,107,559	301,827	22,758	1,432,144
2004	50,749	76,258	142,200	1,156,863	303,216	24,734	1,484,813
2005	46,234	71,310	131,348	1,160,311	300,663	23,399	1,484,373
2006	47,617	81,103	140,861	1,182,884	300,458	20,420	1,503,762
2007	46,658	85,666	147,235	1,202,135	301,171	19,702	1,523,008
2008	50,214	84,914	146,822	1,204,162	303,331	20,318	1,527,811

Source: U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety, *Natural Gas Transmission, Gas Distribution, and Hazardous Liquid Pipeline Annual Mileage*, available at http://ops.dot.gov/stats.htm as of Apr. 28, 2010. Totals may not sum due to independent rounding.

Table 2-8 splits natural gas pipelines into three types: distribution mains, transmission pipelines, and gathering lines. Gathering lines are low-volume pipelines that gather natural gas from production sites to deliver directly to gas processing plants or compression stations that connect numerous gathering lines to transport gas primarily to processing plants. Transmission pipelines move large volumes of gas to or from processing plants to distribution points. From these distribution points, the gas enters a distribution system that delivers the gas to final consumers. Table 2-8 shows gathering lines decreasing from 1990 from above 30,000 miles from 1990 to 1995 to around 20,000 miles in 2007 and 2008. Transmission pipelines added

about 10,000 miles during this period, from about 292,000 in 1990 to about 303,000 miles in 2008. The most significant growth among all types of pipeline was in distribution, which increased about 260,000 miles during the 1990 to 2008 period, driving an increase in total natural gas pipeline mileage (Figure 2-1). The growth in distribution is likely driven by expanding production as well as expanding gas markets in growing U.S. towns and cities.

2.4.3 Domestic Consumption

Historical crude oil sector-level consumption trends for 1990 through 2009 are shown in Table 2-9 and Figure 2-4. Total consumption rose gradually until 2008 when consumption dropped as a result of the economic recession. The share of residential, commercial, industrial, and electric power on a percentage basis declined during this period, while the share of total consumption by the transportation sector rose from 64 percent in 1990 to 71 percent in 2009.

Table 2-9 Crude Oil Consumption by Sector, 1990-2009

		Percent of Total				
Year	Total (million bbl)	Residential	Commercial	Industrial	Transportation Sector	Electric Power
1990	6,201	4.4	2.9	25.3	64.1	3.3
1991	6,101	4.4	2.8	25.2	64.4	3.1
1992	6,234	4.4	2.6	26.5	63.9	2.5
1993	6,291	4.5	2.4	25.7	64.5	2.9
1994	6,467	4.3	2.3	26.3	64.4	2.6
1995	6,469	4.2	2.2	25.9	65.8	1.9
1996	6,701	4.4	2.2	26.3	65.1	2.0
1997	6,796	4.2	2.0	26.6	65.0	2.2
1998	6,905	3.8	1.9	25.6	65.7	3.0
1999	7,125	4.2	1.9	25.8	65.4	2.7
2000	7,211	4.4	2.1	24.9	66.0	2.6
2001	7,172	4.3	2.1	24.9	65.8	2.9
2002	7,213	4.1	1.9	25.0	66.8	2.2
2003	7,312	4.2	2.1	24.5	66.5	2.7
2004	7,588	4.0	2.0	25.2	66.2	2.6
2005	7,593	3.9	1.9	24.5	67.1	2.6
2006	7,551	3.3	1.7	25.1	68.5	1.4
2007	7,548	3.4	1.6	24.4	69.1	1.4
2008	7,136	3.7	1.8	23.2	70.3	1.1
2009*	6,820	3.8	1.8	22.5	71.1	0.9

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 consumption is preliminary.

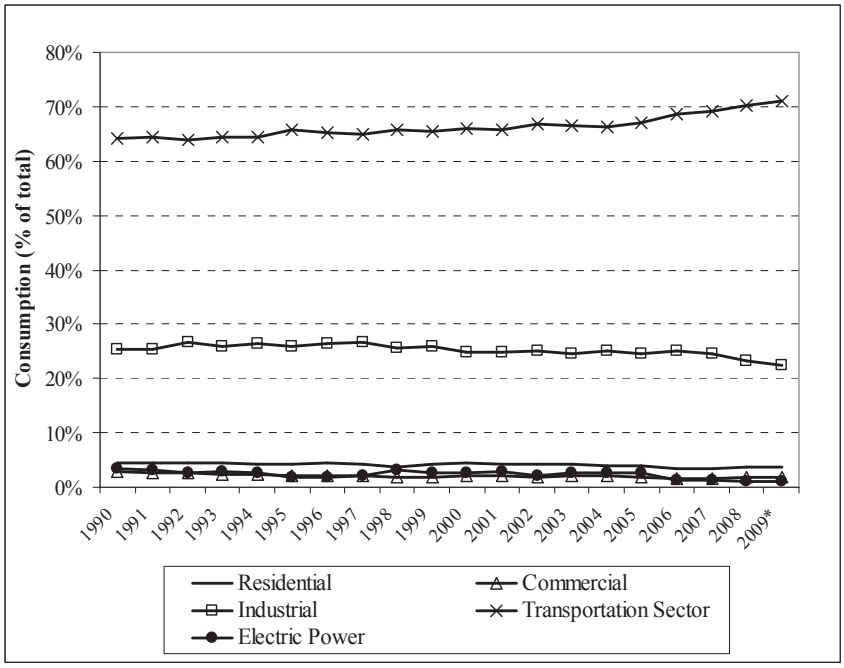


Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2009

Natural gas consumption has increased over the last twenty years. From 1990 to 2009, total U.S. consumption increased by an average of about 1 percent per year (Table 2-10 and Figure 2-5). Over the same period, industrial consumption of natural gas declined, whereas electric power generation increased its consumption quite dramatically, an important trend in the industry as many utilities increasingly use natural gas for peak generation or switch from coal-based to natural gas-based electricity generation. The residential, commercial, and transportation sectors maintained their consumption levels at more or less constant levels during this time period.

Table 2-10 Natural Gas Consumption by Sector, 1990-2009

Year	Total (bcf)	Percent of Total				
		Residential	Commercial	Industrial	Transportation Sector	Electric Power
1990	19,174	22.9	13.7	43.1	3.4	16.9
1991	19,562	23.3	13.9	42.7	3.1	17.0
1992	20,228	23.2	13.9	43.0	2.9	17.0
1993	20,790	23.8	13.8	42.7	3.0	16.7
1994	21,247	22.8	13.6	42.0	3.2	18.4
1995	22,207	21.8	13.6	42.3	3.2	19.1
1996	22,609	23.2	14.0	42.8	3.2	16.8
1997	22,737	21.9	14.1	42.7	3.3	17.9
1998	22,246	20.3	13.5	42.7	2.9	20.6
1999	22,405	21.1	13.6	40.9	2.9	21.5
2000	23,333	21.4	13.6	39.8	2.8	22.3
2001	22,239	21.5	13.6	38.1	2.9	24.0
2002	23,007	21.2	13.7	37.5	3.0	24.7
2003	22,277	22.8	14.3	37.1	2.7	23.1
2004	22,389	21.7	14.0	37.3	2.6	24.4
2005	22,011	21.9	13.6	35.0	2.8	26.7
2006	21,685	20.1	13.1	35.3	2.8	28.7
2007	23,097	20.4	13.0	34.1	2.8	29.6
2008	23,227	21.0	13.5	33.9	2.9	28.7
2009*	22,834	20.8	13.6	32.4	2.9	30.2

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 consumption is preliminary. Totals may not sum due to independent rounding.

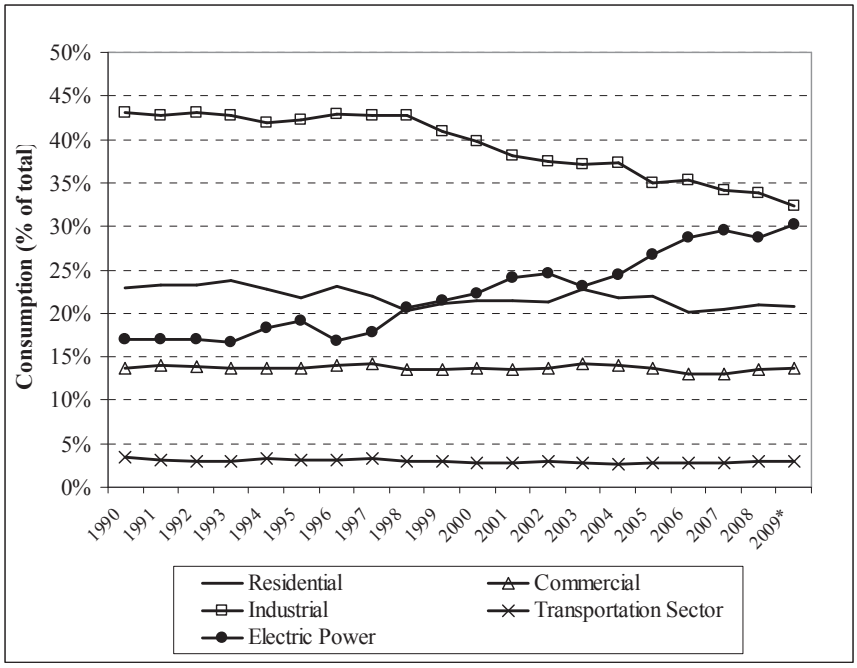


Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2009

2.4.4 International Trade

Imports of crude oil and refined petroleum products have increased over the last twenty years, showing increased substitution of imports for domestic production, as well as imports satisfying growing consumer demand in the U.S (Table 2-11). Crude oil imports have increased by about 2 percent per year on average, whereas petroleum products have increased by 1 percent on average per year.

Table 2-11 Total Crude Oil and Petroleum Products Imports (Million Bbl), 1990-2009

Year	Crude Oil	Petroleum Products	Total Petroleum
1990	2,151	775	2,926
1991	2,111	673	2,784
1992	2,226	661	2,887
1993	2,477	669	3,146
1994	2,578	706	3,284
1995	2,639	586	3,225
1996	2,748	721	3,469
1997	3,002	707	3,709
1998	3,178	731	3,908
1999	3,187	774	3,961
2000	3,320	874	4,194
2001	3,405	928	4,333
2002	3,336	872	4,209
2003	3,528	949	4,477
2004	3,692	1,119	4,811
2005	3,696	1,310	5,006
2006	3,693	1,310	5,003
2007	3,661	1,255	4,916
2008	3,581	1,146	4,727
2009	3,307	973	4,280

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** * 2009 Imports are preliminary.

Natural gas imports also increased steadily from 1990 to 2007 in volume and percentage terms (Table 2-12). The years 2007 and 2008 saw imported natural gas constituting a lower percentage of domestic natural gas consumption. In 2009, the U.S exported 700 bcf natural gas to Canada, 338 bcf to Mexico via pipeline, and 33 bcf to Japan in LNG-form. In 2009, the U.S. primarily imported natural gas from Canada (3268 bcf, 87 percent) via pipeline, although a growing percentage of natural gas imports are in LNG-form shipped from countries such as Trinidad and Tobago and Egypt. Until recent years, industry analysts forecast that LNG imports would continue to grow as a percentage of U.S consumption. However, it is possible that increasingly accessible domestic unconventional gas resources, such as shale gas and coalbed methane, might reduce the need for the U.S. to import natural gas, either via pipeline or shipped LNG.

Table 2-12 Natural Gas Imports and Exports, 1990-2009

Year	Total Imports (bcf)	Total Exports (bcf)	Net Imports (bcf)	Percent of U.S. Consumption
1990	1,532	86	1,447	7.5
1991	1,773	129	1,644	8.4
1992	2,138	216	1,921	9.5
1993	2,350	140	2,210	10.6
1994	2,624	162	2,462	11.6
1995	2,841	154	2,687	12.1
1996	2,937	153	2,784	12.3
1997	2,994	157	2,837	12.5
1998	3,152	159	2,993	13.5
1999	3,586	163	3,422	15.3
2000	3,782	244	3,538	15.2
2001	3,977	373	3,604	16.2
2002	4,015	516	3,499	15.2
2003	3,944	680	3,264	14.7
2004	4,259	854	3,404	15.2
2005	4,341	729	3,612	16.4
2006	4,186	724	3,462	16.0
2007	4,608	822	3,785	16.4
2008	3,984	1,006	2,979	12.8
2009*	3,748	1,071	2,677	11.7

Source: U.S. Energy Information Administration, **Annual Energy Review 2010.** 2009 Imports are preliminary.

2.4.5 Forecasts

In this section, we provide forecasts of well drilling activity and crude oil and natural gas domestic production, imports, and prices. The forecasts are from the 2011 Annual Energy Outlook produced by EIA, the most current forecast information available from EIA. As will be discussed in detail in Section 3, to analyze the impacts of the proposed NSPS on the national energy economy, we use the National Energy Modeling System (NEMS) that was used to produce the 2011 Annual Energy Outlook.

Table 2-13 and Figure 2-6 present forecasts of successful wells drilled in the U.S. from 2010 to 2035. Crude oil well forecasts for the lower 48 states show a rise from 2010 to a peak in 2019, which is followed by a gradual decline until the terminal year in the forecast, totaling a 28 percent decline for the forecast period. The forecast of successful offshore crude oil wells shows a variable but generally increasing trend.

Table 2-13 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

	Lower 48 U.S. States					Offshore		Totals	
Year	Crude Oil	Conventional Natural Gas	Tight Sands	Devonian Shale	Coalbed Methane	Crude Oil	Natural gas	Crude Oil	Natural Gas
2010	12,082	7,302	2,393	4,196	2,426	74	56	12,155	16,373
2011	10,271	7,267	2,441	5,007	1,593	81	73	10,352	16,380
2012	10,456	7,228	2,440	5,852	1,438	80	71	10,536	17,028
2013	10,724	7,407	2,650	6,758	1,564	79	68	10,802	18,447
2014	10,844	7,378	2,659	6,831	1,509	85	87	10,929	18,463
2015	10,941	7,607	2,772	7,022	1,609	84	87	11,025	19,096
2016	11,015	7,789	2,817	7,104	1,633	94	89	11,108	19,431
2017	11,160	7,767	2,829	7,089	1,631	104	100	11,264	19,416
2018	11,210	7,862	2,870	7,128	1,658	112	101	11,323	19,619
2019	11,268	8,022	2,943	7,210	1,722	104	103	11,373	20,000
2020	10,845	8,136	3,140	7,415	2,228	89	81	10,934	21,000
2021	10,849	8,545	3,286	7,621	2,324	91	84	10,940	21,860
2022	10,717	8,871	3,384	7,950	2,361	90	77	10,807	22,642
2023	10,680	9,282	3,558	8,117	2,499	92	96	10,772	23,551
2024	10,371	9,838	3,774	8,379	2,626	87	77	10,458	24,694
2025	10,364	10,200	3,952	8,703	2,623	93	84	10,457	25,562
2026	10,313	10,509	4,057	9,020	2,705	104	103	10,417	26,394
2027	10,103	10,821	4,440	9,430	2,862	99	80	10,202	27,633
2028	9,944	10,995	4,424	9,957	3,185	128	111	10,072	28,672
2029	9,766	10,992	4,429	10,138	3,185	121	127	9,887	28,870
2030	9,570	11,161	4,512	10,539	3,240	127	103	9,697	29,556
2031	9,590	11,427	4,672	10,743	3,314	124	109	9,714	30,265
2032	9,456	11,750	4,930	11,015	3,449	143	95	9,599	31,239
2033	9,445	12,075	5,196	11,339	3,656	116	107	9,562	32,372
2034	9,278	12,457	5,347	11,642	3,669	128	92	9,406	33,206
2035	8,743	13,003	5,705	12,062	3,905	109	108	8,852	34,782

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.**

Meanwhile, Table 2-13 and Figure 2-6 show increases for all types of natural gas drilling in the lower 48 states. Drilling in shale reservoirs is expected to rise most dramatically, about 190 percent during the forecast period, while drilling in coalbed methane and tight sands reservoirs increase significantly, 61 percent and 138 percent, respectively. Despite the growth in drilling in unconventional reservoirs, EIA forecasts successful conventional natural gas wells to increase about 78 percent during this period. Offshore natural gas wells are also expected to increase during the next 25 years, but not to the degree of onshore drilling.

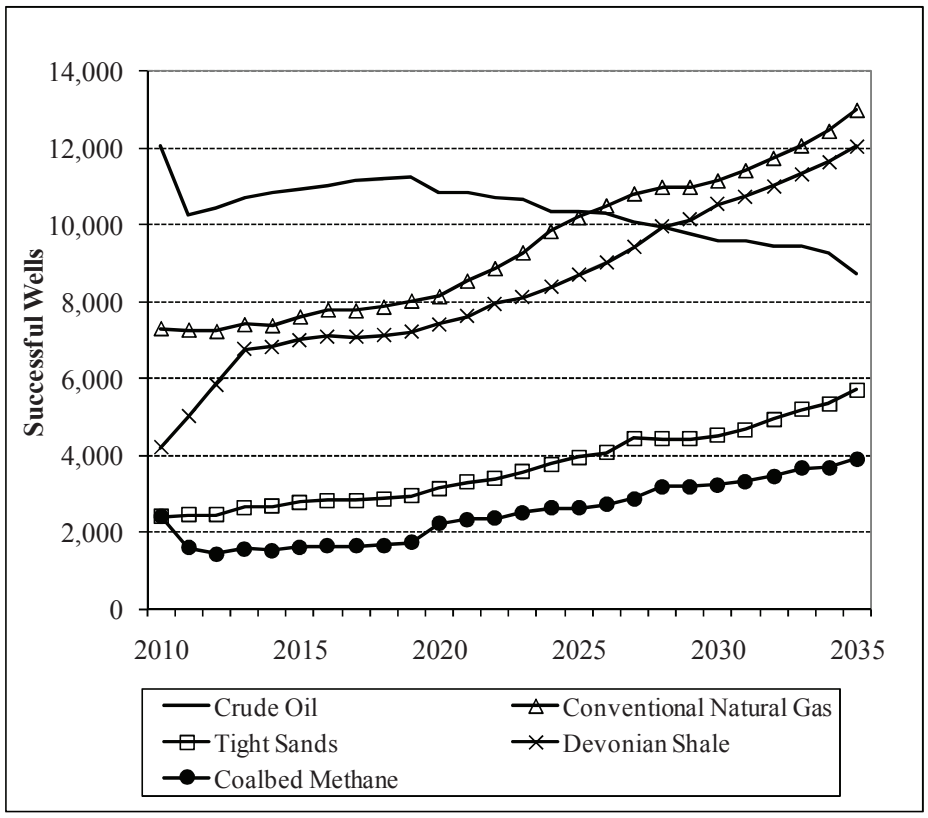


Figure 2-6 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

Table 2-14 presents forecasts of domestic crude oil production, reserves, imports and prices. Domestic crude oil production increases slightly during the forecast period, with much of the growth coming from onshore production in the lower 48 states. Alaskan oil production is forecast to decline from 2010 to a low of 99 million barrels in 2030, but rising above that level for the final five years of the forecast. Net imports of crude oil are forecast to decline slightly during the forecast period. Figure 2-7 depicts these trends graphically. All told, EIA forecasts total crude oil to decrease about 3 percent from 2010 to 2035.

Table 2-14 Forecast of Crude Oil Supply, Reserves, and Wellhead Prices, 2010-2035

	Domestic Production (million bbls)							
Year	Total Domestic	Lower 48 Onshore	Lower 48 Offshore	Alaska	Lower 48 End of Year Reserves	Net Imports	Total Crude Supply (million bbls)	Lower 48 Average Wellhead Price (2009 dollars per bbl)
2010	2,011	1,136	653	223	17,634	3,346	5,361	78.6
2011	1,993	1,212	566	215	17,955	3,331	5,352	84.0
2012	1,962	1,233	529	200	18,026	3,276	5,239	86.2
2013	2,037	1,251	592	194	18,694	3,259	5,296	88.6
2014	2,102	1,267	648	188	19,327	3,199	5,301	92.0
2015	2,122	1,283	660	179	19,690	3,177	5,299	95.0
2016	2,175	1,299	705	171	20,243	3,127	5,302	98.1
2017	2,218	1,320	735	163	20,720	3,075	5,293	101.0
2018	2,228	1,323	750	154	21,129	3,050	5,277	103.7
2019	2,235	1,343	746	147	21,449	3,029	5,264	105.9
2020	2,219	1,358	709	153	21,573	3,031	5,250	107.4
2021	2,216	1,373	680	163	21,730	3,049	5,265	108.8
2022	2,223	1,395	659	169	21,895	3,006	5,229	110.3
2023	2,201	1,418	622	161	21,921	2,994	5,196	112.0
2024	2,170	1,427	588	155	21,871	2,996	5,166	113.6
2025	2,146	1,431	566	149	21,883	3,010	5,155	115.2
2026	2,123	1,425	561	136	21,936	3,024	5,147	116.6
2027	2,114	1,415	573	125	22,032	3,018	5,131	117.8
2028	2,128	1,403	610	116	22,256	2,999	5,127	118.8
2029	2,120	1,399	614	107	22,301	2,988	5,108	119.3
2030	2,122	1,398	625	99	22,308	2,994	5,116	119.5
2031	2,145	1,391	641	114	22,392	2,977	5,122	119.6
2032	2,191	1,380	675	136	22,610	2,939	5,130	118.8
2033	2,208	1,365	691	152	22,637	2,935	5,143	119.1
2034	2,212	1,351	714	147	22,776	2,955	5,167	119.2
2035	2,170	1,330	698	142	22,651	3,007	5,177	119.5

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.** Totals may not sum due to independent rounding.

Table 2-14 also shows forecasts of proved reserves in the lower 48 states. The reserves forecast shows steady growth from 2010 to 2035, an increase of 28 percent overall. This increment is larger than the forecast increase in production from the lower 48 states during this period, 8 percent, showing reserves are forecast to grow more rapidly than production. Table 2-14 also

shows average wellhead prices increasing a total of 52 percent from 2010 to 2035, from $78.6 per barrel to $119.5 per barrel in 2008 dollar terms.

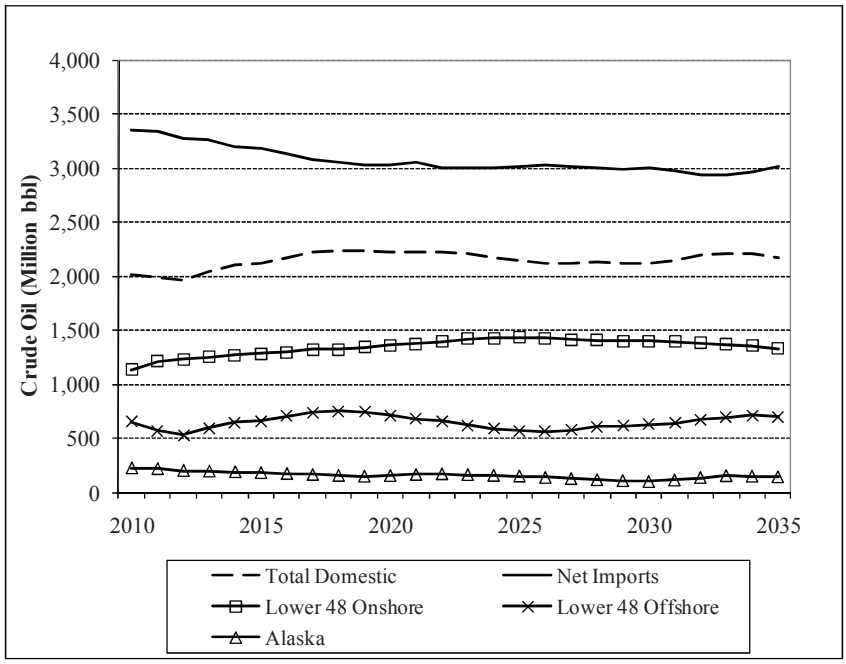


Figure 2-7 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2035

Table 2-15 shows domestic natural gas production is forecast to increase about 24 percent from 2010 to 2035. Contrasted against the much higher growth in natural gas wells drilled as shown in Table 2-13, per well productivity is expected to continue its declining trend. Meanwhile, imports of natural gas via pipeline are expected to decline during the forecast period almost completely, from 2.33 tcf in 2010 to 0.04 in 2035 tcf. Imported LNG also decreases from 0.41 tcf in 2010 to 0.14 tcf in 2035. Total supply, then, increases about 10 percent, from 24.08 tcf in 2010 to 26.57 tcf in 2035.

Table 2-15 Forecast of Natural Gas Supply, Lower 48 Reserves, and Wellhead Price

	Production		Net Imports				
Year	Dry Gas Production	Supplemental Natural Gas	Net Imports (Pipeline)	Net Imports (LNG)	Total Supply	Lower 48 End of Year Dry Reserves	Average Lower 48 Wellhead Price (2009 dollars per Mcf)
2010	21.28	0.07	2.33	0.41	24.08	263.9	4.08
2011	21.05	0.06	2.31	0.44	23.87	266.3	4.09
2012	21.27	0.06	2.17	0.47	23.98	269.1	4.09
2013	21.74	0.06	2.22	0.50	24.52	272.5	4.15
2014	22.03	0.06	2.26	0.45	24.80	276.6	4.16
2015	22.43	0.06	2.32	0.36	25.18	279.4	4.24
2016	22.47	0.06	2.26	0.36	25.16	282.4	4.30
2017	22.66	0.06	2.14	0.41	25.28	286.0	4.33
2018	22.92	0.06	2.00	0.43	25.40	289.2	4.37
2019	23.20	0.06	1.75	0.47	25.48	292.1	4.43
2020	23.43	0.06	1.40	0.50	25.40	293.6	4.59
2021	23.53	0.06	1.08	0.52	25.19	295.1	4.76
2022	23.70	0.06	0.89	0.49	25.14	296.7	4.90
2023	23.85	0.06	0.79	0.45	25.15	297.9	5.08
2024	23.86	0.06	0.77	0.39	25.08	298.4	5.27
2025	23.99	0.06	0.74	0.34	25.12	299.5	5.43
2026	24.06	0.06	0.71	0.27	25.10	300.8	5.54
2027	24.30	0.06	0.69	0.22	25.27	302.1	5.67
2028	24.59	0.06	0.67	0.14	25.47	304.4	5.74
2029	24.85	0.06	0.63	0.14	25.69	306.6	5.78
2030	25.11	0.06	0.63	0.14	25.94	308.5	5.82
2031	25.35	0.06	0.57	0.14	26.13	310.1	5.90
2032	25.57	0.06	0.50	0.14	26.27	311.4	6.01
2033	25.77	0.06	0.38	0.14	26.36	312.6	6.12
2034	26.01	0.06	0.23	0.14	26.44	313.4	6.24
2035	26.33	0.06	0.04	0.14	26.57	314.0	6.42

Source: U.S. Energy Information Administration, **Annual Energy Outlook 2011.** Totals may not sum due to independent rounding.

2.5 Industry Costs

2.5.1 Finding Costs

Real costs of drilling oil and natural gas wells have increased significantly over the past two decades, particularly in recent years. Cost per well has increased by an annual average of about 15 percent, and cost per foot has increased on average of about 13 percent per year (Figure 2-8).

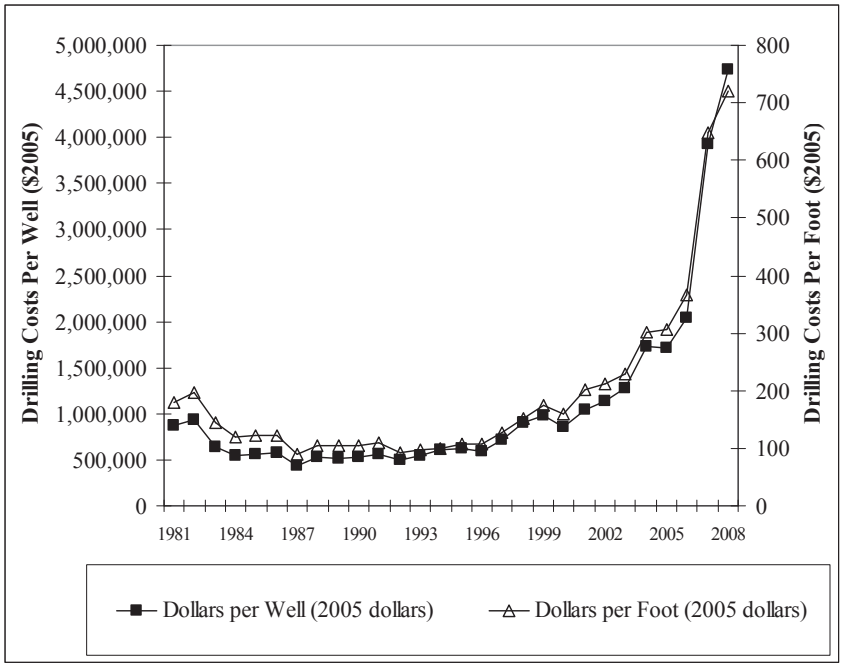


Figure 2-8 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008

The average finding costs compiled and published by EIA add an additional level of detail to drilling costs, in that finding costs incorporate the costs more broadly associated with adding proved reserves of crude oil and natural gas. These costs include exploration and development costs, as well as costs associated with the purchase or leasing of real property. EIA publishes finding costs as running three-year averages, in order to better compare these costs, which occur over several years, with annual average lifting costs. Figure 2-9 shows average domestic onshore and offshore and foreign finding costs for the sample of U.S. firms in EIA's Financial Reporting System (FRS) database from 1981 to 2008. The costs are reported in 2008 dollars on a barrel of oil equivalent basis for crude oil and natural gas combined. The average domestic finding costs dropped from 1981 until the mid-1990s. Interestingly, in the mid-1990s, domestic onshore and offshore and foreign finding costs converged for a few years. After this period, offshore finding costs rose faster than domestic onshore and foreign costs.

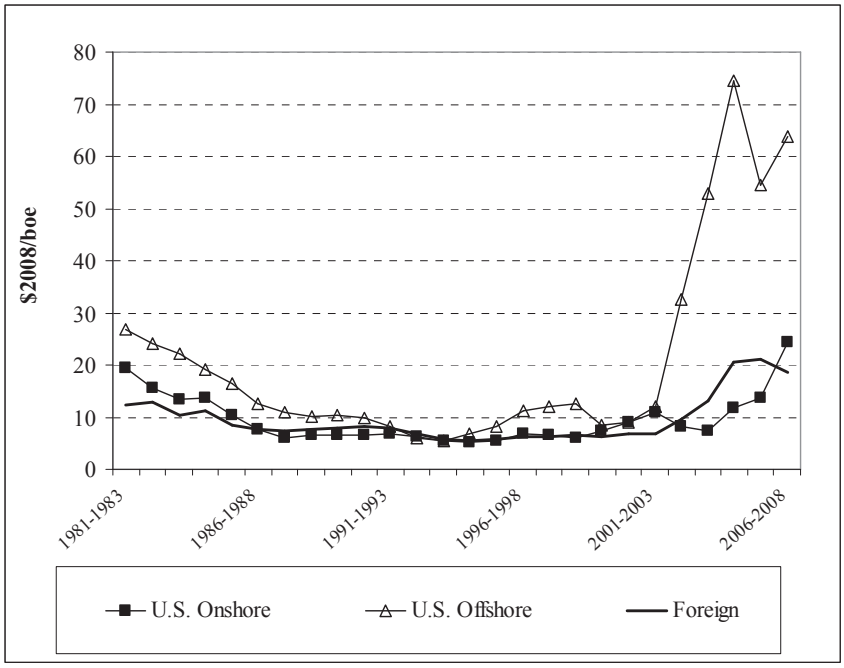


Figure 2-9 Finding Costs for FRS Companies, 1981-2008

After 2000, average finding costs rose sharply, with the finding costs for domestic onshore and offshore and foreign proved reserves diverging onto different trajectories. Note the drilling costs in Figure 2-8 and finding costs in Figure 2-9 present similar trends overall.

2.5.2 Lifting Costs

Lifting costs are the costs to produce crude oil or natural gas once the resource has been found and accessed. EIA's definition of lifting costs includes costs of operating and maintaining wells and associated production equipment. Direct lifting costs exclude production taxes or royalties, while total lifting costs includes taxes and royalties. Like finding costs, EIA reports average lifting costs for FRS firms in 2008 dollars on a barrel of oil equivalent basis. Total lifting costs are the sum of direct lifting costs and production taxes. Figure 2-10 depicts direct lifting cost trends from 1981 to 2008 for domestic and foreign production.

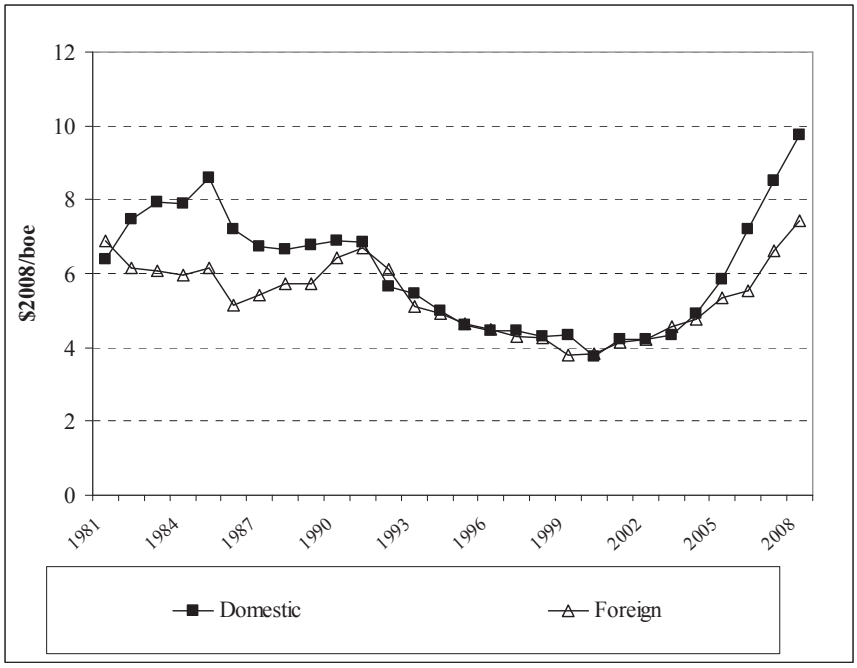


Figure 2-10 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2008 (3-year Running Average)

Direct lifting costs (excludes taxes and royalties) for domestic production rose a little more than $2 per barrels of oil equivalent from 1981 to 1985, then declined almost $5 per barrel of oil equivalent from 1985 until 2000. From 2000 to 2008, domestic lifting costs increased sharply, about $6 per barrel of oil equivalent. Foreign lifting costs diverged from domestic lifting costs from 1981 to 1991, as foreign lifting costs were lower than domestic costs during this period. Foreign and domestic lifting costs followed a similar track until they again diverged in 2004, with domestic lifting again becoming more expensive. Combined with finding costs, the total finding and lifting costs rose significantly in from 2000 to 2008.

2.5.3 Operating and Equipment Costs

The EIA report, "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009"[2], contains indices and estimated costs for domestic oil and natural gas equipment and production operations. The indices and cost trends track costs for representative operations in

[2] U.S. Energy Information Administration. "Oil and Gas Lease Equipment and Operating Costs 1994 through 2009." September 28, 2010. <http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/cost_indices_equipment_production/current/coststudy.html> Accessed February 2, 2011.

six regions (California, Mid-Continent, South Louisiana, South Texas, West Texas, and Rocky Mountains) with producing depths ranging from 2000 to 16,000 feet and low to high production rates (for example, 50,000 to 1 million cubic feet per day for natural gas).

Figure 2-11 depicts crude oil operating costs and equipment costs indices for 1976 to 2009, as well as the crude oil price in 1976 dollars. The indices show that crude oil operating and equipment costs track the price of oil over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and oil prices rose steeply in the late 1970s, but generally decreased from about 1980 until the late 1990s.

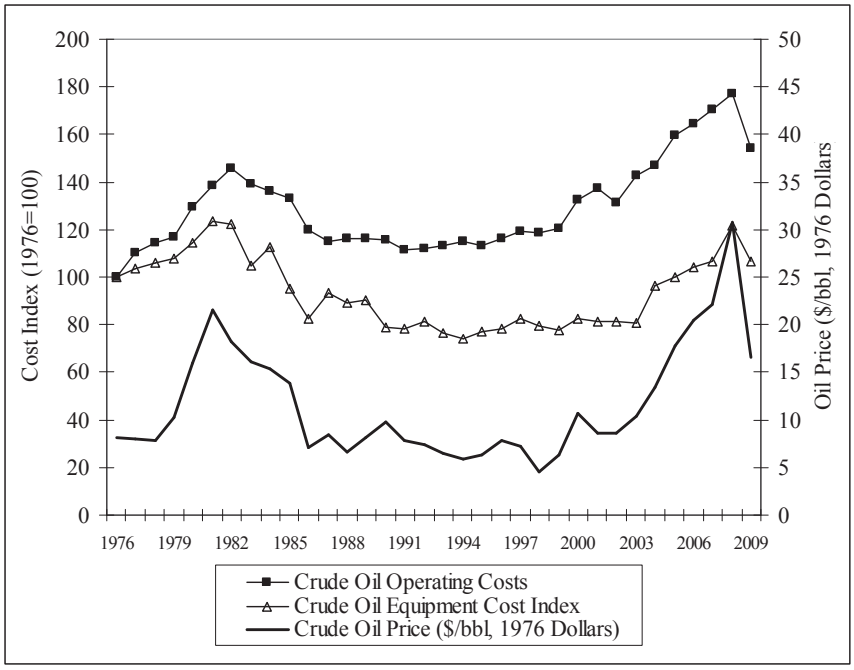


Figure 2-11 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009

Oil costs and prices again generally rose between 2000 to present, with a peak in 2008. The 2009 index values for crude oil operating and equipment costs are 154 and 107, respectively.

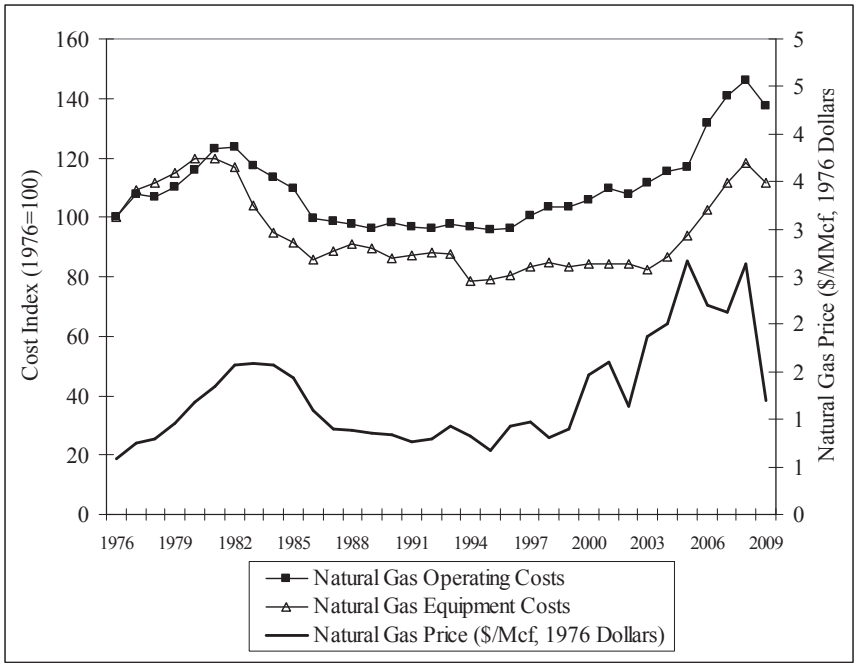


Figure 2-12 Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009

Figure 2-12 depicts natural gas operating and equipment costs indices, as well as natural gas prices. Similar to the cost trends for crude oil, natural gas operating and equipment costs track the price of natural gas over this time period, while operating costs have risen more quickly than equipment costs. Operating and equipment costs and gas prices also rose steeply in the late 1970s, but generally decreased from about 1980 until the mid 1990s. The 2009 index values for natural gas operating and equipment costs are 137 and 112, respectively.

2.6 Firm Characteristics

A regulatory action to reduce pollutant discharges from facilities producing crude oil and natural gas will potentially affect the business entities that own the regulated facilities. In the oil and natural gas production industry, facilities comprise those sites where plant and equipment extract, process, and transport extracted streams recovered from the raw crude oil and natural gas resources. Companies that own these facilities are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility.

2.6.1 Ownership

Enterprises in the oil and natural gas industry may be divided into different groups that include producers, transporters, and distributors. The producer segment may be further divided between major and independent producers. Major producers include large oil and gas companies

that are involved in each of the five industry segments: drilling and exploration, production, transportation, refining, and marketing. Independent producers include smaller firms that are involved in some but not all of the five activities.

According to the Independent Petroleum Association of America (IPAA), independent companies produce approximately 68 percent of domestic crude oil production of our oil, 85 percent of domestic natural gas, and drill almost 90 percent of the wells in the U.S (IPAA, 2009). Through the mid-1980s, natural gas was a secondary fuel for many producers. However, now it is of primary importance to many producers. IPAA reports that about 50 percent of its members' spending in 2007 was directed toward natural gas production, largely toward production of unconventional gas (IPAA, 2009). Meanwhile, transporters are comprised of the pipeline companies, while distributors are comprised of the local distribution companies.

2.6.2 Size Distribution of Firms in Affected

As of 2007, there were 6,563 firms within the 211111 and 211112 NAICS codes, of which 6427 (98 percent) were considered small businesses (Table 2-16). Within NAICS 211111 and 211112, large firms compose about 2 percent of the firms, but account for 59 percent of employment and generate about 80 percent of estimated receipts listed under the NAICS.

Table 2-16 SBA Size Standards and Size Distribution of Oil and Natural Gas Firms

NAICS	NAICS Description	SBA Size Standard	Small Firms	Large Firms	Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	98	41	139
213111	Drilling Oil and Gas Wells	500	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	61*	65*	126
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	500	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	24,683
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	500	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	N/A*	N/A*	20,796,681

Note: *The counts of small and large firms in NAICS 486210 is based upon firms with less than $7.5 million in receipts, rather than the $7 million required by the SBA Size Standard. We used this value because U.S. Census reports firm counts for firms with receipts less than $7.5 million. **Employment and receipts could not be split between small and large businesses because of non-disclosure requirements faced by the U.S. Census Bureau.
Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007." <http://www.census.gov/econ/susb/>

The small and large firms within NAICS 21311 are similarly distributed, with large firms accounting for about 2 percent of firms, but 66 percent and 69 percent of employment and estimated receipts, respectively. Because there are relatively few firms within NAICS 486210, the Census Bureau cannot release breakdowns of firms by size in sufficient detail to perform similar calculation.

2.6.3 Trends in National Employment and Wages

As well as producing much of the U.S. energy supply, the oil and natural gas industry directly employs a significant number of people. Table 2-17 shows employment in oil and natural gas-related NAICS codes from 1990 to 2009. The overall trend shows a decline in total industry employment throughout the 1990s, hitting a low of 313,703 in 1999, but rebounding to a 2008 peak of 511,805. Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Support Activities for Oil and Gas Operations (NAICS 213112) employ the majority of workers in the industry.

Table 2-17 Oil and Natural Gas Industry Employment by NAICS, 1990-09

Year	Crude Petroleum and Natural Gas Extraction (211111)	Natural Gas Liquid Extraction (211112)	Drilling of Oil and Natural Gas Wells (213111)	Support Activities for Oil and Gas Ops. (213112)	Pipeline Trans. of Crude Oil (486110)	Pipeline Trans. of Natural Gas (486210)	Total
1990	182,848	8,260	52,365	109,497	11,112	47,533	411,615
1991	177,803	8,443	46,466	116,170	11,822	48,643	409,347
1992	169,615	8,819	39,900	99,924	11,656	46,226	376,140
1993	159,219	7,799	42,485	102,840	11,264	43,351	366,958
1994	150,598	7,373	44,014	105,304	10,342	41,931	359,562
1995	142,971	6,845	43,114	104,178	9,703	40,486	347,297
1996	139,016	6,654	46,150	107,889	9,231	37,519	346,459
1997	137,667	6,644	55,248	117,460	9,097	35,698	361,814
1998	133,137	6,379	53,943	122,942	8,494	33,861	358,756
1999	124,296	5,474	41,868	101,694	7,761	32,610	313,703
2000	117,175	5,091	52,207	108,087	7,657	32,374	322,591
2001	119,099	4,500	62,012	123,420	7,818	33,620	30,469
2002	116,559	4,565	48,596	120,536	7,447	31,556	329,259
2003	115,636	4,691	51,526	120,992	7,278	29,684	329,807
2004	117,060	4,285	57,332	128,185	7,073	27,340	341,275
2005	121,535	4,283	66,691	145,725	6,945	27,341	372,520
2006	130,188	4,670	79,818	171,127	7,202	27,685	420,690
2007	141,239	4,842	84,525	197,100	7,975	27,431	463,112
2008	154,898	5,183	92,640	223,635	8,369	27,080	511,805
2009	155,150	5,538	67,756	193,589	8,753	26,753	457,539

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2011 , <http://www.bls.gov/cew/>

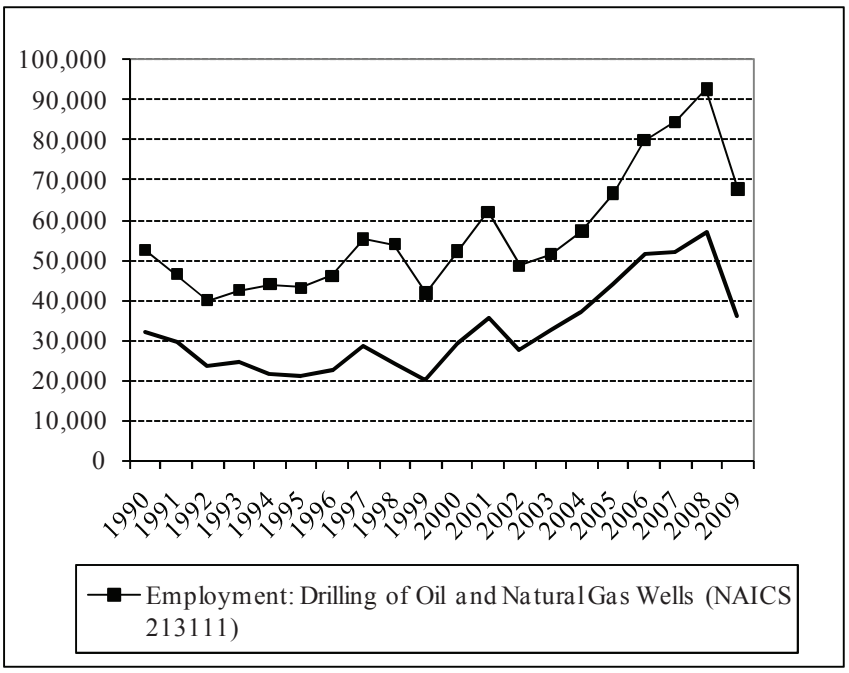


Figure 2-13 Employment in Drilling of Oil and Natural Gas Wells (NAICS 213111), and Total Oil and Natural Gas Wells Drilled, 1990-2009

Figure 2-13 compares employment in Drilling of Oil and Natural Gas Wells (NAICS 213111) with the total number of oil and natural gas wells drilled from 1990 to 2009. The figure depicts a strong positive correlation between employment in the sector with drilling activity. This correlation also holds throughout the period covered by the data.

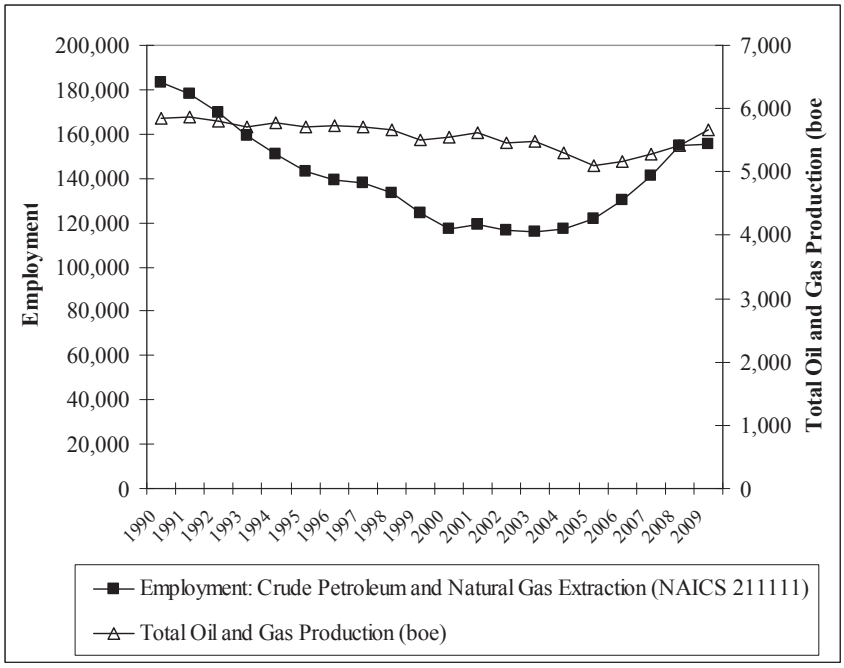


Figure 2-14 Employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Total Crude Oil and Natural Gas Production (boe), 1990-2009

Figure 2-14 compares employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) with total domestic oil and natural gas production from 1990 to 2009 in barrels of oil equivalent terms. While until 2003, employment in this sector and total production declined gradually, employment levels declined more rapidly. However, from 2004 to 2009 employment in Extraction recovered, rising to levels similar to the early 1990s.

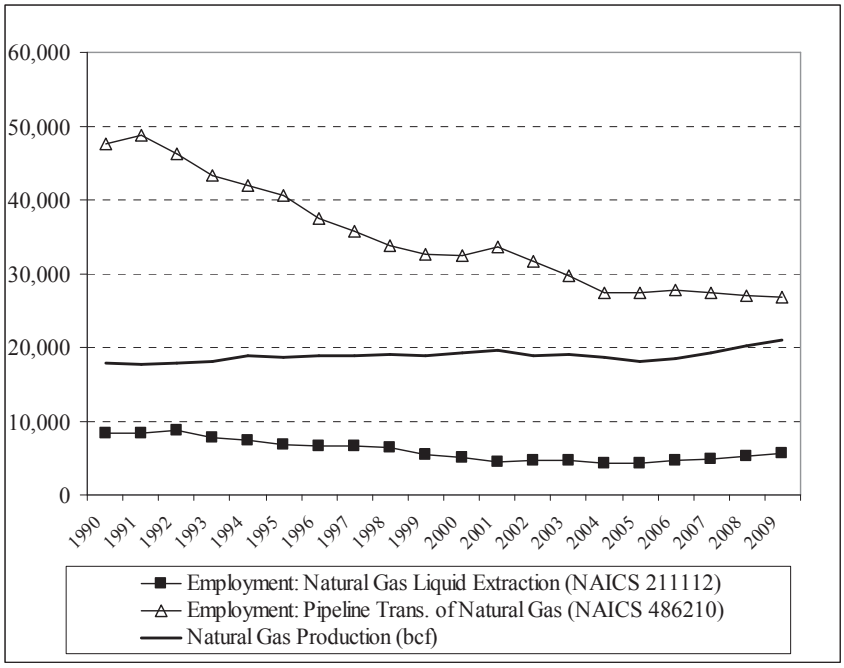


Figure 2-15 Employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009

Figure 2-15 depicts employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009. While total natural gas production has risen slightly over this time period, employment in natural gas pipeline transportation has steadily declined to almost half of its 1991 peak. Employment in natural gas liquid extraction declined from 1992 to a low in 2005, then rebounded slightly from 2006 to 2009. Overall, however, these trends depict these sectors becoming decreasingly labor intensive, unlike the trends depicted in Figure 2-13 and Figure 2-14.

From 1990 to 2009, average wages for the oil and natural gas industry have increased. Table 2-18 and Figure 2-16 show real wages (in 2008 dollars) from 1990 to 2009 for the NAICS codes associated with the oil and natural gas industry.

Table 2-18 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 (2008 dollars)

Year	Crude Petroleum and Natural Gas Extraction (211111)	Natural Gas Liquid Extraction (211112)	Drilling of Oil and Natural Gas Wells (213111)	Support Activities for Oil and Gas Operations (213112)	Pipeline Transportation of Crude Oil (486110)	Pipeline Transportation of Natural Gas (486210)	Total
1990	71,143	66,751	42,215	45,862	68,044	61,568	59,460
1991	72,430	66,722	43,462	47,261	68,900	65,040	60,901
1992	76,406	68,846	43,510	48,912	74,233	67,120	64,226
1993	77,479	68,915	45,302	50,228	72,929	67,522	64,618
1994	79,176	70,875	44,577	50,158	76,136	68,516	64,941
1995	81,433	67,628	46,243	50,854	78,930	71,965	66,446
1996	84,211	68,896	48,872	52,824	76,841	76,378	68,391
1997	89,876	79,450	52,180	55,600	78,435	82,775	71,813
1998	93,227	89,948	53,051	57,578	79,089	84,176	73,722
1999	98,395	89,451	54,533	59,814	82,564	94,471	79,078
2000	109,744	112,091	60,862	60,594	81,097	130,630	86,818
2001	111,101	111,192	61,833	61,362	83,374	122,386	85,333
2002	109,957	103,653	62,196	59,927	87,500	91,550	82,233
2003	110,593	112,650	61,022	61,282	87,388	91,502	82,557
2004	121,117	118,311	63,021	62,471	93,585	93,684	86,526
2005	127,243	127,716	70,772	67,225	92,074	90,279	90,292
2006	138,150	133,433	74,023	70,266	91,708	98,691	94,925
2007	135,510	132,731	82,010	71,979	96,020	105,441	96,216
2008	144,542	125,126	81,961	74,021	101,772	99,215	99,106
2009	133,575	123,922	80,902	70,277	100,063	100,449	96,298

Source: U.S. Bureau of Labor Statistics, Quarterly Census of Employment and Wages, 2011 , <http://www.bls.gov/cew/>

Employees in the NAICS 211 codes enjoy the highest average wages in the industry, while employees in the NAICS 213111 code have relatively lower wages. Average wages in natural gas pipeline transportation show the highest variation, with a rapid climb from 1990 to 2000, more than doubling in real terms. However, since 2000 wages have declined in the pipeline transportation sector, while wages have risen in the other NAICS.

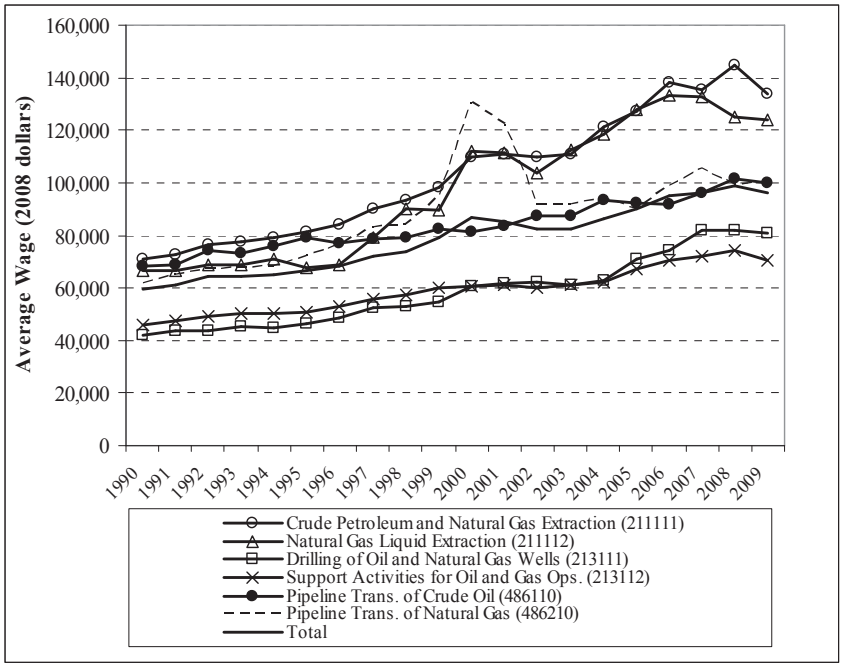


Figure 2-16 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 ($2008)

2.6.4 Horizontal and Vertical Integration

Because of the existence of major companies, the industry possesses a wide dispersion of vertical and horizontal integration. The vertical aspects of a firm's size reflect the extent to which goods and services that can be bought from outside are produced in house, while the horizontal aspect of a firm's size refers to the scale of production in a single-product firm or its scope in a multiproduct one. Vertical integration is a potentially important dimension in analyzing firm-level impacts because the regulation could affect a vertically integrated firm on more than one level. The regulation may affect companies for whom oil and natural gas production is only one of several processes in which the firm is involved. For example, a company that owns oil and natural gas production facilities may ultimately produce final petroleum products, such as motor gasoline, jet fuel, or kerosene. This firm would be considered vertically integrated because it is involved in more than one level of requiring crude oil and natural gas and finished petroleum products. A regulation that increases the cost of oil and natural gas production will ultimately affect the cost of producing final petroleum products.

Horizontal integration is also a potentially important dimension in firm-level analyses for any of the following reasons. A horizontally integrated firm may own many facilities of which

only some are directly affected by the regulation. Additionally, a horizontally integrated firm may own facilities in unaffected industries. This type of diversification would help mitigate the financial impacts of the regulation. A horizontally integrated firm could also be indirectly as well as directly affected by the regulation.

In addition to the vertical and horizontal integration that exists among the large firms in the industry, many major producers often diversify within the energy industry and produce a wide array of products unrelated to oil and gas production. As a result, some of the effects of regulation of oil and gas production can be mitigated if demand for other energy sources moves inversely compared to petroleum product demand.

In the natural gas sector of the industry, vertical integration is less predominant than in the oil sector. Transmission and local distribution of natural gas usually occur at individual firms, although processing is increasing performed by the integrated major companies. Several natural gas firms operate multiple facilities. However, natural gas wells are not exclusive to natural gas firms only. Typically wells produce both oil and gas and can be owned by a natural gas firm or an oil company.

Unlike the large integrated firms that have several profit centers such as refining, marketing, and transportation, most independents have to rely only on profits generated at the wellhead from the sale of oil and natural gas or the provision of oil and gas production-related engineering or financial services. Overall, independent producers typically sell their output to refineries or natural gas pipeline companies and are not vertically integrated. Independents may also own relatively few facilities, indicating limited horizontal integration.

2.6.5 Firm-level Information

The annual *Oil and Gas Journal* (OGJ) survey, the OGJ150, reports financial and operating results for top 150 public oil and natural gas companies with domestic reserves and headquarters in the U.S. In the past, the survey reported information on the top 300 companies, now the top 150. In 2010, only 137 companies are listed[3]. Table 2-19 lists selected statistics for

[3] Oil and Gas Journal. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010.

the top 20 companies in 2010. The results presented in the table reflect relatively lower production and financial figures as a result of the economic recession of this period.

Total earnings for the top 137 companies fell from 2008 to 2009 from $71 billion to $27 billion, reflecting the weak economy. Revenues for these companies also fell 35 percent during this period. 69 percent of the firms posted net losses in 2009, compared to 46 percent one year earlier (*Oil and Gas Journal*, September 6, 2010).

The total worldwide liquids production for the 137 firms declined 0.5 percent to 2.8 billion bbl, while total worldwide gas production increased about 3 percent to a total of 16.5 tcf (*Oil and Gas Journal*, September 6, 2010). Meanwhile, the 137 firms on the OGJ list increased both oil and natural gas production and reserves from 2008 to 2009. Domestic production of liquids increased about 7 percent to 1.1 billion bbl, and natural gas production increased to 10.1 tcf. For context, the OGJ150 domestic crude production represents about 57 percent of total domestic production (1.9 billion bbl, according to EIA). The OGJ150 natural gas production represents about 54 percent of total domestic production (18.8 tcf, according to EIA).

The OGJ also releases a period report entitled "Worldwide Gas Processing Survey", which provides a wide range of information on existing processing facilities. We used a recent list of U.S. gas processing facilities (*Oil and Gas Journal*, June 7, 2010) and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. As of 2009, there are 579 gas processing facilities in the U.S., with a processing capacity of 73,767 million cubic feet per day and throughout of 45,472 million cubic feet per day (Table 2-20). The overall trend in U.S. gas processing capacity is showing fewer, but larger facilities. For example, in 1995, there were 727 facilities with a capacity of 60,533 million cubic feet per day (U.S. DOE, 2006).

Trends in gas processing facility ownership are also showing a degree of concentration, as large firms own multiple facilities, which also tend to be relatively large facilities (Table 2-20). While we estimate 142 companies own the 579 facilities, the top 20 companies (in terms of total throughput) own 264 or 46 percent of the facilities. That larger companies tend to own larger facilities is indicated by these top 20 firms owning 86 percent of the total capacity and 88 percent of actual throughput.

Table 2-19 Top 20 Oil and Natural Gas Companies (Based on Total Assets), 2010

Rank by Total Assets	Company	Employees	Total Assets ($ millions)	Total Rev. ($ millions)	Net Inc. ($ millions)	Worldwide Production		U.S. Production		Net Wells Drilled
						Liquids (Million bbl)	Natural Gas (Bcf)	Liquids (Million bbl)	Natural Gas (Bcf)	
1	ExxonMobil Corp.	102,700	233,323	310,586	19,280	725	2,383	112	566	466
2	Chevron Corp.	64,000	164,621	171,636	10,563	674	1,821	177	511	594
3	ConocoPhillips	30,000	152,588	152,840	4,858	341	1,906	153	850	692
4	Anadarko Petroleum Corp.	4,300	50,123	9,000	-103	88	817	63	817	630
5	Marathon Oil Corp.	28,855	47,052	54,139	1,463	90	351	23	146	115
6	Occidental Petroleum Corp.	10,100	44,229	15,531	2,915	179	338	99	232	260
7	XTO Energy Inc.	3,129	36,255	9,064	2,019	32	855	32	855	1,059
8	Chesapeake Energy Corp.	8,200	29,914	7,702	-5,805	12	835	12	835	1,003
9	Devon Energy Corp.	5,400	29,686	8,015	-2,479	72	966	43	743	521
10	Hess Corp.	13,300	29,465	29,569	740	107	270	26	39	48
11	Apache Corp.	3,452	28,186	8,615	-284	106	642	35	243	124
12	El Paso Corp.	4,991	22,505	4,631	-539	6	219	6	215	134
13	EOG Resources Inc.	2,100	18,119	14,787	547	29	617	26	422	652
14	Murphy Oil Corp.	8,369	12,756	18,918	838	48	68	6	20	3
15	Noble Energy Inc.	1,630	11,807	2,313	-131	29	285	17	145	540
16	Williams Cos. Inc.	4,801	9,682	2,219	400	0	3,435	0	3,435	488
17	Questar Corp.	2,468	8,898	3,054	393	4	169	4	169	194
18	Pioneer Nat. Resources Co.	1,888	8,867	1,712	-52	19	157	17	148	67
19	Plains Expl. & Prod. Co.	808	7,735	1,187	136	18	78	18	78	53
20	Petrohawk Energy Corp.	469	6,662	41,084	-1,025	2	174	2	174	162

Source: *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010.
Notes: The source for employment figures is the American Business Directory.

Table 2-20 Top 20 Natural Gas Processing Firms (Based on Throughput), 2009

Rank	Company	Processing Plants (No.)	Natural Gas Capacity (MMcf/day)	Natural Gas Throughput (MMcf/day)
1	BP PLC	19	13,378	11,420
2	DCP Midstream Inc.	64	9,292	5,586
3	Enterprise Products Operating LP—	23	10,883	5,347
4	Targa Resources	16	4,501	2,565
5	Enbridge Energy Partners LP—	19	3,646	2,444
6	Williams Cos.	10	4,826	2,347
7	Martin Midstream Partners	16	3,384	2,092
8	Chevron Corp.	23	1,492	1,041
9	Devon Gas Services LP	6	1,038	846
10	ExxonMobil Corp.	6	1,238	766
11	Occidental Petroleum Corp	7	776	750
12	Kinder Morgan Energy Partners	9	1,318	743
13	Enogex Products Corp.	8	863	666
14	Hess Corp.	3	1,060	613
15	Norcen Explorer	1	600	500
16	Copano Energy	1	700	495
17	Anadarko	18	816	489
18	Oneok Field Services	10	1,751	472
19	Shell	4	801	446
20	DTE Energy	1	800	400
	TOTAL FOR TOP 20	264	63,163	40,028
	TOTAL FOR ALL COMPANIES	579	73,767	45,472

Source: *Oil and Gas Journal*. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010, with additional analysis to determine ultimate ownership of plants.

The OGJ also issues a periodic report on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies, which amounts to 136 companies in 2010 (*Oil and Gas Journal*, November 1, 2010). Table 2-21 presents the pipeline mileage, volumes of natural gas transported, operating revenue, and net income for the top 20 U.S. natural gas pipeline companies in 2009. Ownership of gas pipelines is mostly independent from ownership of oil and gas production companies, as is seen from the lack of overlap between the OGJ list of pipeline companies and the OGJ150. This observation shows that the pipeline industry is still largely based upon firms serving regional market.

The top 20 companies maintain about 63 percent of the total pipeline mileage and transport about 54 percent of the volume of the industry (Table 2-21). Operating revenues of the

top 20 companies equaled $11.5 billion, representing 60 percent of the total operating revenues for major and non-major companies. The top 20 companies also account for 64 percent of the net income of the industry.

Table 2-21 Performance of Top 20 Gas Pipeline Companies (Based on Net Income), 2009

Rank	Company	Transmission (miles)	Vol. trans for others (MMcf)	Op. Rev. (thousand $)	Net Income
1	Natural Gas Pipeline Co of America	9,312	1,966,774	1,131,548	348,177
2	Dominion Transmission Inc.	3,452	609,193	831,773	212,365
3	Columbia Gas Transmission LLC	9,794	1,249,188	796,437	200,447
4	Panhandle Eastern Pipe Line Co. LP	5,894	675,616	377,563	196,825
5	Transcontinental Gas Pipe Line Co. LLC	9,362	2,453,295	1,158,665	192,830
6	Texas Eastern Transmission LP	9,314	1,667,593	870,812	179,781
7	Northern Natural Gas Co.	15,028	922,745	690,863	171,427
8	Florida Gas Transmission Co. LLC	4,852	821,297	520,641	164,792
9	Tennessee Gas Pipeline Co.	14,113	1,704,976	820,273	147,378
10	Southern Natural Gas Co.	7,563	867,901	510,500	137,460
11	El Paso Natural Gas Co.	10,235	1,493,213	592,503	126,000
12	Gas Transmission Northwest Corp.	1,356	809,206	216,526	122,850
13	Rockies Express Pipeline LLC	1,682	721,840	555,288	117,243
14	CenterPoint Energy Gas Transmission Co.	6,162	1,292,931	513,315	116,979
15	Colorado Interstate Gas Co.	4,200	839,184	384,517	108,483
16	Kern River Gas Transmission Co.	1,680	789,858	371,951	103,430
17	Trunkline LNG Co. LLC	—	—	134,150	101,920
18	Northwest Pipeline GP	3,895	817,832	434,379	99,340
19	Texas Gas Transmission LLC	5,881	1,006,906	361,406	91,575
20	Algonquin Gas Transmission LLC	1,128	388,366	237,291	82,472
	TOTAL FOR TOP 20	124,903	21,097,914	11,510,401	3,021,774
	TOTAL FOR ALL COMPANIES	198,381	38,793,532	18,934,674	4,724,456

Source: *Oil and Gas Journal*. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

2.6.6 Financial Performance and Condition

From a broad industry perspective, the EIA Financial Reporting System (FRS) collects financial and operating information from a subset of the U.S. major energy producing companies. This information is used in annual report to Congress, as well as is released to the public in aggregate form. While the companies that report information to FRS each year changes, EIA makes an effort to retain sufficient consistency such that trends can be evaluated.

For 2008, there are 27 companies in the FRS[4] that accounted for 41 percent of total U.S. crude oil and NGL production, 43 percent of natural gas production, 77 percent of U.S. refining capacity, and 0.2 percent of U.S. electricity net generation (U.S. EIA, 2010). Table 2-22 shows a series of financial trends in 2008 dollars selected and aggregated from FRS firms' financial statements. The table shows operating revenues and expenses rising significantly from 1990 to 2008, with operating income (the difference between operating revenues and expenses) rising as well. Interest expenses remained relatively flat during this period. Meanwhile, recent years have shown that other income and income taxes have played a more significant role for the industry. Net income has risen as well, although 2008 saw a decline from previous periods, as oil and natural gas prices declined significantly during the latter half of 2008.

Table 2-22 Selected Financial Items from Income Statements (Billion 2008 Dollars)

Year	Operating Revenues	Operating Expenses	Operating Income	Interest Expense	Other Income*	Income Taxes	Net Income
1990	766.9	706.4	60.5	16.8	13.6	24.8	32.5
1991	673.4	635.7	37.7	14.4	13.4	15.4	21.3
1992	670.2	637.2	33.0	12.7	-5.6	12.2	2.5
1993	621.4	586.6	34.8	11.0	10.3	12.7	21.5
1994	606.5	565.6	40.9	10.8	6.8	14.4	22.5
1995	640.8	597.5	43.3	11.1	12.9	17.0	28.1
1996	706.8	643.3	63.6	9.1	13.4	26.1	41.8
1997	673.6	613.8	59.9	8.2	13.4	23.9	41.2
1998	614.2	594.1	20.1	9.2	11.0	6.0	15.9
1999	722.9	682.6	40.3	10.9	12.7	13.6	28.6
2000	1,114.3	1,011.8	102.5	12.9	18.4	42.9	65.1
2001	961.8	880.3	81.5	10.8	7.6	33.1	45.2
2002	823.0	776.9	46.2	12.7	7.9	17.2	24.3
2003	966.9	872.9	94.0	10.1	19.5	37.2	66.2
2004	1,188.5	1,051.1	137.4	12.4	20.1	54.2	90.9
2005	1,447.3	1,263.8	183.5	11.6	34.6	77.1	129.3
2006	1,459.0	1,255.0	204.0	12.4	41.2	94.8	138.0
2007	1,475.0	1,297.7	177.3	11.1	47.5	86.3	127.4
2008	1,818.1	1,654.0	164.1	11.4	32.6	98.5	86.9

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). * Other Income includes other revenue and expense (excluding interest expense), discontinued operations, extraordinary items, and accounting changes. Totals may not sum due to independent rounding.

[4] Alenco, Anadarko Petroleum Corporation, Apache Corporation, BP America, Inc., Chesapeake Energy Corporation, Chevron Corporation, CITGO Petroleum Corporation, ConocoPhillips, Devon Energy Corporation, El Paso Corporation, EOG Resources, Inc., Equitable Resources, Inc., Exxon Mobil Corporation, Hess Corporation, Hovensa, Lyondell Chemical Corporation, Marathon Oil Corporation, Motiva Enterprises, L.L.C., Occidental Petroleum Corporation, Shell Oil Company, Sunoco, Inc., Tesoro Petroleum Corporation, The Williams Companies, Inc., Total Holdings USA, Inc., Valero Energy Corp., WRB Refining LLC, and XTO Energy, Inc.

Table 2-23 shows in percentage terms the estimated return on investments for a variety of business lines, in 1998, 2003, and 2008, for FRS companies. For U.S. petroleum-related business activities, oil and natural gas production has remained the most profitable line of business relative to refining/marketing and pipelines, sustaining a return on investment greater than 10 percent for the three years evaluated. Returns to foreign oil and natural gas production rose above domestic production in 2008. Electric power generation and sales emerged in 2008 as a highly profitable line of business for the FRS companies.

Table 2-23 Return on Investment for Lines of Business (all FRS), for 1998, 2003, and 2008 (percent)

Line of Business	1998	2003	2008
Petroleum	10.8	13.4	12.0
U.S. Petroleum	10	13.7	8.2
Oil and Natural Gas Production	12.5	16.5	10.7
Refining/Marketing	6.6	9.3	2.6
Pipelines	6.7	11.5	2.4
Foreign Petroleum	11.9	13.0	17.8
Oil and Natural Gas Production	12.5	14.2	16.3
Refining/Marketing	10.6	8.0	26.3
Downstream Natural Gas*	-	8.8	5.1
Electric Power*	-	5.2	181.4
Other Energy	7.1	2.8	-2.1
Non-energy	10.9	2.4	-5.3

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System). Note: Return on investment measured as contribution to net income/net investment in place. * The downstream natural gas and electric power lines of business were added to the EIA-28 survey form beginning with the 2003 reporting year.

The oil and natural gas industry also produces significant tax revenues for local, state, and federal authorities. Table 2-24 shows income and production tax trends from 1990 to 2008 for FRS companies. The column with U.S. federal, state, and local taxes paid or accrued includes deductions for the U.S. Federal Investment Tax Credit ($198 million in 2008) and the effect of the Alternative Minimum Tax ($34 million in 2008). Income taxes paid to state and local authorizes were $3,060 million in 2008, about 13 percent of the total paid to U.S. authorities.

Table 2-24 Income and Production Taxes, 1990-2008 (Million 2008 Dollars)

Year	U.S. Federal, State, and Local Taxes Paid or Accrued	Total Current	Total Deferred	Total Income Tax Expense	Other Non-Income Production Taxes Paid
1990	9,568	25,056	-230	24,826	4,341
1991	6,672	18,437	-3,027	15,410	3,467
1992	4,994	16,345	-4,116	12,229	3,097
1993	3,901	13,983	-1,302	12,681	2,910
1994	3,348	13,556	887	14,443	2,513
1995	6,817	17,474	-510	16,965	2,476
1996	8,376	22,493	3,626	26,119	2,922
1997	7,643	20,764	3,141	23,904	2,743
1998	1,199	7,375	-1,401	5,974	1,552
1999	2,626	13,410	140	13,550	2,147
2000	14,308	36,187	6,674	42,861	3,254
2001	10,773	28,745	4,351	33,097	3,042
2002	814	17,108	46	17,154	2,617
2003	9,274	30,349	6,879	37,228	3,636
2004	19,661	50,185	4,024	54,209	3,990
2005	29,993	72,595	4,529	77,125	5,331
2006	29,469	85,607	9,226	94,834	5,932
2007	28,332	84,119	2,188	86,306	7,501
2008	23,199	95,590	2,866	98,456	12,507

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The difference between total current taxes and U.S. federal, state, and local taxes in includes taxes and royalties paid to foreign countries. As can be seen in Table 2-24, foreign taxes paid far exceeds domestic taxes paid. Other non-income production taxes paid, which have risen almost three-fold between 1990 and 2008, include windfall profit and severance taxes, as well as other production-related taxes.

2.7 References

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3 EMISSIONS AND ENGINEERING COSTS

3.1 Introduction

This section includes three sets of discussions for both the proposed NSPS and NESHAP amendments:

- Emission Sources and Points
- Emissions Control Options
- Engineering Cost Analysis

3.2 Emissions Points, Controls, and Engineering Costs Analysis

This section discusses the emissions points and pollution control options for the proposed NSPS and NESHAP amendments. This discussion of emissions points and control options is meant to assist the reader of the RIA in better understanding the economic impact analysis. However, we provide reference to the detailed technical memoranda prepared by the Office of Air Quality Planning and Standards (OAQPS) for the reader interested in a greater level of detail. This section also presents the engineering cost analysis, which provides a cost basis for the energy system, welfare, employment, and small business analyses.

Before going into detail on emissions points and pollution controls, it is useful to provide estimates of overall emissions from the crude oil and natural industry to provide context for estimated reductions as a result of the regulatory options evaluated. To estimate VOC emissions from the oil and gas sector, we modified the emissions estimate for the crude oil and natural gas sector in the 2008 National Emissions Inventory (NEI). During this review, EPA identified VOC emissions from natural gas sources which are likely relatively under-represented in the NEI, natural gas well completions primarily. Crude oil and natural gas sector VOC emissions estimated in the 2008 NEI total approximately 1.76 million tons. Of these emissions, the NEI identifies about 21 thousand tons emitted from natural gas well completion processes. We substituted the estimates of VOC emissions from natural gas well completions estimated as part of the engineering analysis (510,000 tons, which is discussed in more detail in the next section), bringing the total estimated VOC emissions from the crude oil and natural gas sector to about 2.24 million tons VOC.

The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009 (published April 2011) estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 251.55 ($MMtCO_2$-e). It is important to note that the 2009 emissions estimates from well completions and recompletions exclude a significant number of wells completed in tight sand plays and the Marcellus Shale, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays and the Marcellus Shale, and such an adjustment is also being considered as a planned improvement in next year's Inventory. This adjustment would increase the 2009 Inventory estimate by about 80 $MMtCO_2$-e to approximately 330 $MMtCO_2$-e.

3.2.1 Emission Points and Pollution Controls assessed in the RIA

3.2.1.1 NSPS Emission Points and Pollution Controls

A series of emissions controls were evaluated as part of the NSPS review. This section provides a basic description of possible emissions sources and the controls evaluated for each source to facilitate the reader's understanding of the economic impact and benefit analyses. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant chapters within the Technical Support Document (TSD) which is published in the Docket. The chapters are also referenced below. EPA is soliciting public comment and data relevant to several emissions-related issues related to the proposed NSPS. The comments we receive during the public comment period will help inform the rule development process as we work toward promulgating a final action.

Centrifugal and reciprocating compressors (TSD Chapter 6)**:** There are many locations throughout the oil and gas sector where compression of natural gas is required to move the gas along the pipeline. This is accomplished by compressors powered by combustion turbines, reciprocating internal combustion engines, or electric motors. Turbine-powered compressors use a small portion of the natural gas that they compress to fuel the turbine. The turbine operates a centrifugal compressor, which compresses and pumps the natural gas through the pipeline. Sometimes an electric motor is used to turn a centrifugal compressor. This type of compression does not require the use of any of the natural gas from the pipeline, but it does require a source of electricity. Reciprocating spark ignition engines are also used to power many compressors,

referred to as reciprocating compressors, since they compress gas using pistons that are driven by the engine. Like combustion turbines, these engines are fueled by natural gas from the pipeline.

Both centrifugal and reciprocating compressors are sources of VOC emissions, and EPA evaluated compressors for coverage under the NSPS. Centrifugal compressors require seals around the rotating shaft to prevent gases from escaping where the shaft exits the compressor casing. The seals in some compressors use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. Very little gas escapes through the oil barrier, but considerable gas is absorbed by the oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated, and the gas is commonly vented to the atmosphere. These are commonly called "wet" seals. An alternative to a wet seal system is the mechanical dry seal system. This seal system does not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and static pressure. Fugitive VOC is emitted from dry seals around the compressor shaft. The use of dry gas seals substantially reduces emissions. In addition, they significantly reduce operating costs and enhance compressor efficiency.

Reciprocating compressors in the natural gas industry leak natural gas during normal operation. The highest volume of gas loss is associated with piston rod packing systems. Packing systems are used to maintain a tight seal around the piston rod, preventing the gas compressed to high pressure in the compressor cylinder from leaking, while allowing the rod to move freely. Monitoring and replacing compressor rod packing systems on a regular basis can greatly reduce VOC emissions.

Equipment leaks (TSD Chapter 8)**:** Equipment leaks are fugitive emissions emanating from valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines, and other process and operation components. There are several potential reasons for equipment leak emissions. Components such as pumps, valves, pressure relief valves, flanges, agitators, and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines, and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. Because of the large number of valves, pumps, and other components within an oil

and gas production, processing, and transmission facility, equipment leaks of volatile emissions from these components can be significant. Natural gas processing plants, especially those using refrigerated absorption, and transmission stations tend to have a large number of components. These types of equipment also exist at production sites and gas transmission/compressor stations. While the number of components at individual transmission/compressor stations is relatively smaller than at processing plants, collectively there are many components that can result in significant emissions. Therefore, EPA evaluated NSPS for equipment leaks for facilities in the production segment of the industry, which includes everything from the wellhead to the point that the gas enters the processing plant or refinery.

Pneumatic controllers (TSD Chapter 5): Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, delta-pressure, and temperature. Pneumatic controllers are widely used in the oil and natural gas sector. In many situations, the pneumatic controllers used in the oil and gas sector make use of the available high-pressure natural gas to regulate temperature, pressure, liquid level, and flow rate across all areas of the industry. In these "gas-driven" pneumatic controllers, natural gas may be released with every valve movement or continuously from the valve control pilot. Not all pneumatic controllers are gas driven. These "non-gas driven" pneumatic controllers use sources of power other than pressurized natural gas. Examples include solar, electric, and instrument air. At oil and gas locations with electrical service, non gas-driven controllers are typically used. Gas-driven pneumatic controllers are typically characterized as "high-bleed" or "low-bleed", where a high-bleed device releases at least 6 cubic feet of gas per hour. EPA evaluated the impact of requiring low-bleed controllers.

Storage vessels (TSD Chapter 7): Crude oil, condensate, and produced water are typically stored in fixed-roof storage vessels. Some vessels used for storing produced water may be open-top tanks. These vessels, which are operated at or near atmospheric pressure conditions, are typically located at tank batteries. A tank battery refers to the collection of process equipment used to separate, treat, and store crude oil, condensate, natural gas, and produced water. The extracted products from productions wells enter the tank battery through the production header, which may collect product from many wells. Emissions from storage vessels are a result of

working, breathing, and flash losses. Working losses occur due to the emptying and filling of storage tanks. Breathing losses are the release of gas associated with daily temperature fluctuations and other equilibrium effects. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas production segment, flashing losses occur when live crude oils or condensates flow into a storage tank from a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flashing emission will occur in the storage stage. The two ways of controlling tanks with significant emissions would be to install a vapor recovery unit (VRU) and recover all the vapors from the tanks or to route the emissions from the tanks to a control device.

Well completions (TSD Chapter 4): In the oil and natural gas sector, well completions contain multi-phase processes with various sources of emissions. One specific emission source during completion activities is the venting of natural gas to the atmosphere during flowback. Flowback emissions are short-term in nature and occur as a specific event during completion of a new well or during activities that involve re-drilling or re-fracturing an existing well. Well completions include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production.

Hydraulic fracturing is one completion step for improving gas production where the reservoir rock is fractured with very high pressure fluid, typically water emulsion with proppant (generally sand) that "props open" the fractures after fluid pressure is reduced. Emissions are a result of the backflow of the fracture fluids and reservoir gas at high velocity necessary to lift excess proppant to the surface. This multi-phase mixture is often directed to a surface impoundment where natural gas and VOC vapors escape to the atmosphere during the collection of water, sand, and hydrocarbon liquids. As the fracture fluids are depleted, the backflow eventually contains more volume of natural gas from the formation. Thus, we estimate completions involving hydraulic fracturing vent substantially more natural gas, approximately 230 times more, than completions not involving hydraulic fracturing. Specifically, we estimate

that uncontrolled well completion emissions for a hydraulically fractured well are about 23 tons of VOC, where emissions for a conventional gas well completion are around 0.1 ton VOC. Our data indicate that hydraulically fractured wells have higher emissions but we believe some wells that are not hydraulically fractured may have higher emissions than our data show, or in some cases, hydraulically fractured wells could have lower emissions that our data show.

Reduced emission completions, which are sometimes referred to as "green completions" or "flareless completions," use equipment at the well site to capture and treat gas so it can be directed into the sales line and avoid emissions from venting. Equipment required to conduct a reduced emissions completion may include tankage, special gas-liquid-sand separator traps, and gas dehydration. Equipment costs associated with reduced emission completions will vary from well to well. Based on information provided to the EPA Natural Gas STAR program, 90 percent of gas potentially vented during a completion can be recovered during a reduced emission completion.

3.2.1.2 NESHAP Emission Points and Pollution Controls

A series of emissions controls will be required under the proposed NESHAP Amendments. This section provides a basic description of potential sources of emissions and the controls intended for each to facilitate the reader's understanding of the economic impacts and subsequent benefits analysis section. The reader who is interested in more technical detail on the engineering and cost basis of the analysis is referred to the relevant technical memos which are published in the Docket. The memos are also referenced below.

Glycol dehydrators[5]: Once natural gas has been separated from any liquid materials or products (e.g., crude oil, condensate, or produced water), residual entrained water is removed from the natural gas by dehydration. Dehydration is necessary because water vapor may form hydrates, which are ice-like structures, and can cause corrosion in or plug equipment lines. The most widely used natural gas dehydration processes are glycol dehydration and solid desiccant

[5] Memorandum. Brown, Heather, EC/R Incorporated, to Bruce Moore and Greg Nizich, EPA/OAQPS/SPPD/FIG. Oil and Natural Gas Production MACT and Natural Gas Transmission and Storage MACT - Glycol Dehydrators: Impacts of MACT Review Options. July 17,2011.

dehydration. Solid desiccant dehydration, which is typically only used for lower throughputs, uses adsorption to remove water and is not a source of HAP emissions. Glycol dehydration is an absorption process in which a liquid absorbent, glycol, directly contacts the natural gas stream and absorbs any entrained water vapor in a contact tower or absorption column. The rich glycol, which has absorbed water vapor from the natural gas stream, leaves the bottom of the absorption column and is directed either to (1) a gas condensate glycol separator (GCG separator or flash tank) and then a reboiler or (2) directly to a reboiler where the water is boiled off of the rich glycol. The regenerated glycol (lean glycol) is circulated, by pump, into the absorption tower. The vapor generated in the reboiler is directed to the reboiler vent. The reboiler vent is a source of HAP emissions. In the glycol contact tower, glycol not only absorbs water but also absorbs selected hydrocarbons, including BTEX and n-hexane. The hydrocarbons are boiled off along with the water in the reboiler and vented to the atmosphere or to a control device.

The most commonly used control device is a condenser. Condensers not only reduce emissions, but also recover condensable hydrocarbon vapors that can be recovered and sold. In addition, the dry non-condensable off-gas from the condenser may be used as fuel or recycled into the production process or directed to a flare, incinerator, or other combustion device.

If present, the GCG separator (flash tank) is also a potential source of HAP emissions. Some glycol dehydration units use flash tanks prior to the reboiler to separate entrained gases, primarily methane and ethane from the glycol. The flash tank off-gases are typically recovered as fuel or recycled to the natural gas production header. However, the flash tank may also be vented directly to the atmosphere. Flash tanks typically enhance the reboiler condenser's emission reduction efficiency by reducing the concentration of non-condensable gases present in the stream prior to being introduced into the condenser.

Storage vessels: Please see the discussion of storage vessels in the NSPS section above.

3.2.2 Engineering Cost Analysis

In this section, we provide an overview of the engineering cost analysis used to estimate the additional private expenditures industry may make in order to comply with the proposed

NSPS and NESHAP amendments. A detailed discussion of the methodology used to estimate cost impacts is presented in series of memos published in the Docket as part of the TSD.

3.2.2.1 NSPS Sources

Table 3-1 shows the emissions sources, points, and controls analyzed in three NSPS regulatory options, which we term Option 1, Option 2, and Option 3. Option 2 was selected for proposal. The proposed Option 2 contains reduced emission completion (REC) and completion combustion requirements for a subset of newly drilled natural gas wells that are hydraulically fractured. Option 2 also requires a subset of wells that are worked over, or recompleted, using hydraulic fracturing to implement RECs. The proposed Option 2 requires emissions reductions from reciprocating compressors at gathering and boosting stations, processing plants, transmission compressor stations, and underground storage facilities. The proposed Option 2 also requires emissions reductions from centrifugal compressors, processing plants, and transmission compressor stations. Finally, the proposed Option 2 requires emissions reductions from pneumatic controllers at oil and gas production facilities and natural gas transmission and storage and reductions from high throughput storage vessels.

Table 3-1 Emissions Sources, Points, and Controls Included in NSPS Options

Emissions Sources and Points	Emissions Control	Option 1	Option 2 (proposed)	Option 3
Well Completions of Post-NSPS Wells				
Hydraulically Fractured Gas Wells that Meet Criteria for Reduced Emissions Completion (REC)	REC	**X**	**X**	**X**
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC	Combustion	**X**	**X**	**X**
Conventional Gas Wells	Combustion			
Oil Wells	Combustion			
Well Recompletions				
Hydraulically Fractured Gas Wells (post-NSPS wells)	REC	**X**	**X**	**X**
Hydraulically Fractured Gas Wells (pre-NSPS wells)	REC		**X**	**X**
Conventional Gas Wells	Combustion			
Oil Wells	Combustion			
Equipment Leaks				
Well Pads	NSPS Subpart VV			**X**
Gathering and Boosting Stations	NSPS Subpart VV			**X**
Processing Plants	NSPS Subpart VVa		**X**	**X**
Transmission Compressor Stations	NSPS Subpart VV			**X**
Reciprocating Compressors				
Well Pads	Annual Monitoring/ Maintenance (AMM)			
Gathering/Boosting Stations	AMM	**X**	**X**	**X**
Processing Plants	AMM	**X**	**X**	**X**
Transmission Compressor Stations	AMM	**X**	**X**	**X**
Underground Storage Facilities	AMM	**X**	**X**	**X**
Centrifugal Compressors				
Processing Plants	Dry Seals/Route to Process or Control	**X**	**X**	**X**
Transmission Compressor Stations	Dry Seals/Route to Process or Control	**X**	**X**	**X**
Pneumatic Controllers -				
Oil and Gas Production	Low Bleed/Route to Process	**X**	**X**	**X**
Natural Gas Transmission and Storage	Low Bleed/Route to Process	**X**	**X**	**X**
Storage Vessels				
High Throughput	95% control	**X**	**X**	**X**
Low Throughput	95% control			

The distinction between Option 1 and the proposed Option 2 is the inclusion of completion combustion and REC requirements for recompletions at existing wells and an equipment leak standard for natural gas processing plants in Option 2. Option 2 requires the implementation of completion combustion and REC for existing wells as well as wells completed after the implementation date of the proposed NSPS. Option 1 applies the requirement only to new wells, not existing wells. The main distinction between proposed Option 2 and Option 3 is the inclusion of a suite of equipment leak standards. These equipment leak standards would apply at well pads, gathering and boosting stations, and transmission compressor stations. Option 1 differs from Option 3 in that it does not include the combustion and REC requirements at existing wells or the full suite of equipment leak standards.

Table 3-2 summarizes the unit level capital and annualized costs for the evaluated NSPS emissions sources and points. The detailed description of costs estimates is provided in the series of technical memos included in the TSD in the document, as referenced in Section 3.2.1 of this RIA. The table also includes the projected number of affected units. Four issues are important to note on Table 3-2: the approach to annualizing costs, the projection of affected units in the baseline; that capital and annualized costs are equated for RECs; and additional natural gas and hydrocarbon condensates that would otherwise be emitted to the environment are recovered from several control options evaluated in the NSPS review.

First, engineering capital costs were annualized using a 7 percent interest rate. However, different emissions control options were annualized using expected lifetimes that were determined to be most appropriate for individual options. For control options evaluated for the NSPS, the following lifetimes were used:

- Reduced emissions completions and combustion devices: 1 year (more discussion of the selection of a one-year lifetime follows in this section momentarily)
- Reciprocating compressors: 3 years
- Centrifugal compressors and pneumatic controllers: 10 years
- Storage vessels: 15 years
- Equipment leaks: 5 to 10 years, depending on specific control

To estimate total annualized engineering compliance costs, we added the annualized costs of each item without accounting for different expected lifetimes. An alternative approach would be to establish an overall, representative project time horizon and annualize costs after consideration of control options that would need to be replaced periodically within the given time horizon. For example, a 15 year project would require replacing reciprocating compressor-related controls five times, but only require a single installation of controls on storage vessels. This approach, however, is equivalent to the approach selected; that is to sum the annualized costs across options, without establishing a representative project time horizon.

Second, the projected number of affected units is the number of units that our analysis shows would be affected in 2015, the analysis year. The projected number of affected units accounts for estimates of the adoption of controls in absence of Federal regulation. While the procedures used to estimate adoption in absence of Federal regulation are presented in detail within the TSD, because REC requirements provide a significant component of the estimated emissions reductions and engineering compliance costs, it is worthwhile to go into some detail on the projected number of RECs within the RIA. We use EIA projections consistent with the Annual Energy Outlook 2011 to estimate the number of natural gas well completions with hydraulic fracturing in 2015, assuming that successful wells drilled in coal bed methane, shale, and tight sands used hydraulic fracturing. Based on this assumption, we estimate that 11,403 wells were successfully completed and used hydraulic fracturing. To approximate the number of wells that would not be required to perform RECs because of the absence of sufficient infrastructure, we draw upon the distinction in EIA analysis between exploratory and developmental wells. We assume exploratory wells do not have sufficient access to infrastructure to perform a REC and are exempt from the REC requirement. These 446 wells are removed from the REC estimate and are assumed to combust emissions using pit flares.

The number of hydraulically fractured recompletions of existing wells was approximated using assumptions found in Subpart W's TSD[6] and applied to well count data found in the proprietary HPDI® database. The underlying assumption is that wells found in coal bed

[6] U.S. Environmental Protection Agency (U.S. EPA). 2010. Greenhouse Gas Emissions Reporting From the Petroleum and Natural Gas Industry: Background Technical Support Document. Climate Change Division. Washington, DC.

methane, shale, and tight sand formations require re-fracture, on average, every 10 years. In other words, 10 percent of the total wells classified as being performed with hydraulic fracturing would perform a recompletion in any given year. Natural gas well recompletions performed without hydraulic fracturing were based only on 2008 well data from HPDI®.

The number of completions and recompletions already controlling emissions in absence of a Federal regulation was estimated based on existing State regulations that require applicable control measures for completions and workovers in specific geographic locations. Based on this criterion, 15 percent of natural gas completions with hydraulic fracturing and 15 percent of existing natural gas workovers with hydraulic fracturing are estimated to be controlled by either flare or REC in absence of Federal regulations. Completions and recompletions without hydraulic fracturing were assumed as having no controls in absence of a Federal regulation. Following these procedures leads to an estimate of 9,313 completions of new wells and 12,050 recompletions of existing wells that will require either a REC under the proposed NSPS in 2015.

It should be noted that natural gas prices are stochastic and, historically, there have been periods where prices have increased or decreased rapidly. These price changes would be expected to affect adoption of emission reduction technologies in absence of regulation, particularly control measures such as RECs that capture emission significantly over short periods of time.

Third, for well completion requirements, annualized costs are set equal to capital costs. We chose to equate the capital and annualized cost because the completion requirements (combustion and RECs) are essentially one-shot events; the emissions controls are applied over the course of a well completion, which will typically range over a few days to a couple of weeks. After this relatively short period of time, there is no continuing control requirement, unless the well is again completed at a later date, sometimes years later. We reasoned that the absence of a continuing requirement makes it appropriate to equate capital and annualized costs.

Fourth, for annualized cost, we present two figures, the annualized costs with revenues from additional natural gas and condensate recovery and annualized costs without additional revenues this product recovery. Several emission controls for the NSPS capture VOC emissions

that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOCs, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. When including the additional natural gas recovery in the cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. RECs also capture saleable condensates that would otherwise be lost to the environment. The engineering analysis assumes a REC will capture 34 barrels of condensate per REC and that the value of this condensate is $70/barrel.

The assumed price for natural gas is within the range of variation of wellhead prices for the 2010-11 period. The $4/Mcf is below the 2015 EIA-forecasted wellhead price, $4.22/Mcf in 2008 dollars. The $4/Mcf payment rate does not reflect any taxes or tax credits that might apply to producers implementing the control technologies. As natural gas prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional natural gas recovery is included. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. A $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million in 2008 dollars.

As will be seen in subsequent analysis, the estimate of revenues from additional product recovery is critical to the economic impact analysis. However, before discussing this assumption in more depth, it is important to further develop the engineering estimates to contextualize the discussion and to provide insight into why, if it is profitable to capture natural gas emissions that are otherwise vented, producers may not already be doing so.

Table 3-3 presents the estimated nationwide compliance costs, emissions reductions, and VOC reduction cost-effectiveness broken down by emissions sources and points for those sources and points evaluated in the NSPS analysis. The reporting and recordkeeping costs for the proposed NSPS Option 2 are estimated at $18,805,398 and are included in Table 3-3. Because of time constraints, we were unable to estimate reporting and recordkeeping costs customized for Options 1 and 3; for these options, we use the same $18,805,398 for reporting and recordkeeping costs for these options.

As can be seen from Table 3-3 controls associated with well completions and recompletions of hydraulically fractured wells provide the largest potential for emissions

reductions from evaluated emissions sources and points, as well as present the most significant compliance costs if revenue from additional natural gas recovery is not included. Emissions reductions from conventional natural gas wells and crude oil wells are clearly not as significant as the potential from hydraulically fractured wells, as was discussed in Section 3.2.1.1.

Several evaluated emissions sources and points are estimated to have net financial savings when including the revenue from additional natural gas recovery. These sources form the core of the three NSPS options evaluated in this RIA. Table 3-4 presents the estimated engineering costs, emissions reductions, and VOC reduction cost-effectiveness for the three NSPS options evaluated in the RIA. The resulting total national annualized cost impact of the proposed NSPS rule (Option 2) is estimated at $740 million per year without considering revenues from additional natural gas recovery. Annual costs for the proposed NSPS are estimated at -$45 million when revenue from additional natural gas recovery is included. All figures are in 2008 dollars.

Table 3-2 Summary of Capital and Annualized Costs per Unit for NSPS Emissions Points

Sources/Emissions Point	Projected No. of Affected Units	Capital Costs (2008$)	Per Unit Annualized Cost (2008$)	
			Without Revenues from Additional Product Recovery	With Revenues from Additional Product Recovery
Well Completions				
Hydraulically Fractured Gas Wells that Meet Criteria for REC	9,313	$33,237	$33,237	-$2,173
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	446	$3,523	$3,523	$3,523
Conventional Gas Wells	7,694	$3,523	$3,523	$3,523
Oil Wells	12,193	$3,523	$3,523	$3,523
Well Recompletions				
Hydraulically Fractured Gas Wells (existing wells)	12,050	$33,237	$33,237	-$2,173
Conventional Gas Wells	42,342	$3,523	$3,523	$3,523
Oil Wells	39,375	$3,523	$3,523	$3,523
Equipment Leaks				
Well Pads	4,774	$68,970	$23,413	$21,871
Gathering and Boosting Stations	275	$239,494	$57,063	$51,174
Processing Plants	29	$7,522	$45,160	$33,884
Transmission Compressor Stations	107	$96,542	$25,350	$25,350
Reciprocating Compressors				
Well Pads	6,000	$6,480	$3,701	$3,664
Gathering/Boosting Stations	210	$5,346	$2,456	$870
Processing Plants	209	$4,050	$2,090	-$2,227
Transmission Compressor Stations	20	$5,346	$2,456	$2,456
Underground Storage Facilities	4	$7,290	$3,349	$3,349
Centrifugal Compressors				
Processing Plants	16	$75,000	$10,678	-$123,730
Transmission Compressor Stations	14	$75,000	$10,678	-$77,622
Pneumatic Controllers -				
Oil and Gas Production	13,632	$165	$23	-$1,519
Natural Gas Trans. and Storage	67	$165	$23	$23
Storage Vessels				
High Throughput	304	$65,243	$14,528	$13,946
Low Throughput	17,086	$65,243	$14,528	$13,946

Table 3-3 Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by Emissions Sources and Points, NSPS, 2015

Source/Emissions Point	Emissions Control	Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
		Without Addl. Revenues	With Addl. Revenues	VOC	Methane	HAP	Without Addl. Revenues	With Addl. Revenues
Well Completions (New Wells)								
Hydraulically Fractured Gas Wells	REC	$309,553,517	-$20,235,748	204,134	1,399,139	14,831	$1,516	-$99
Hydraulically Fractured Gas Wells	Combustion	$1,571,188	$1,571,188	9,801	67,178	712	$160	$160
Conventional Gas Wells	Combustion	$27,104,761	$27,104,761	857	5,875	62	$31,619	$31,619
Oil Wells	Combustion	$42,954,036	$42,954,036	83	88	0	$520,580	$520,580
Well Recompletions (Existing Wells)								
Hydraulically Fractured Gas Wells (existing wells)	REC	$400,508,928	-$26,181,572	264,115	1,810,245	19,189	$1,516	-$99
Conventional Gas Wells	Combustion	$149,164,257	$149,164,257	316	2,165	23	$472,227	$472,227
Oil Wells	Combustion	$138,711,979	$138,711,979	44	47	0	$3,134,431	$3,134,431
Equipment Leaks								
Well Pads	NSPS Subpart VV	$111,773,662	$104,412,154	10,646	38,287	401	$10,499	$9,808
Gathering and Boosting Stations	NSPS Subpart VV	$15,692,325	$14,072,850	2,340	8,415	88	$6,705	$6,013
Processing Plants	NSPS Subpart VVa	$1,309,650	$982,648	392	1,411	15	$3,343	$2,508
Transmission Compressor Stations	NSPS Subpart VV	$2,712,450	$2,712,450	261	9,427	8	$10,389	$10,389
Reciprocating Compressors								
Well Pads	Annual Monitoring/ Maintenance (AMM)	$22,204,209	$21,984,763	263	947	10	$84,379	$83,545
Gathering/Boosting Stations	AMM	$515,764	$182,597	400	1,437	15	$1,291	$457
Processing Plants	AMM	$436,806	-$465,354	1,082	3,892	41	$404	-$430
Transmission Compressor Stations	AMM	$47,892	$47,892	12	423	0	$4,093	$4,093
Underground Storage Facilities	AMM	$13,396	$13,396	2	87	0	$5,542	$5,542

Table 3-3 (continued) Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by Emissions Sources and Points, NSPS, 2015

Source/Emissions Point	Emissions Control	Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
		Without Addl. Revenues	With Addl. Revenues	VOC	Methane	HAP	Without Addl. Revenues	With Addl. Revenues
Centrifugal Compressors								
Processing Plants	Dry Seals/Route to Process or Control	$170,853	-$1,979,687	288	3,183	10	$593	-$6,874
Transmission Compressor Stations	Dry Seals/Route to Process or Control	$149,496	-$1,086,704	43	1,546	1	$3,495	-$25,405
Pneumatic Controllers -								
Oil and Gas Production	Low Bleed/Route to Process	$320,071	-$20,699,918	25,210	90,685	952	$13	-$821
Natural Gas Trans. and Storage	Low Bleed/Route to Process	$1,539	$1,539	6	212	0	$262	$262
Storage Vessels								
High Throughput	95% control	$4,411,587	$4,234,856	29,654	6,490	876	$149	$143
Low Throughput	95% control	$248,225,012	$238,280,976	6,838	1,497	202	$36,298	$34,844

Table 3-4 Estimated Engineering Compliance Costs, NSPS (2008$)

	Option 1	Option 2 (Proposed)	Option 3
Capital Costs	$337,803,930	$738,530,998	$1,143,984,622
Annualized Costs			
Without Revenues from Additional Natural Gas Product Recovery	$336,163,858	$737,982,436	$868,160,873
With Revenues from Additional Natural Gas Product Recovery	-$19,496,449	-$44,695,374	$76,502,080
VOC Reductions (tons per year)	270,695	535,201	548,449
Methane Reduction (tons per year)	1,574,498	3,386,154	3,442,283
HAP Reductions (tons per year)	17,442	36,645	37,142
VOC Reduction Cost-Effectiveness ($/ton without additional product revenues)	$1,241.86	$1,378.89	$1,582.94
VOC Reduction Cost-Effectiveness ($/ton with additional product revenues)	-$72.02	-$83.51	$139.49

Note: the VOC reduction cost-effectiveness estimate assumes there is no benefit to reducing methane and HAP, which is not the case. We however present the per ton costs of reducing the single pollutant for illustrative purposes. As product prices can increase or decrease rapidly, the estimated engineering compliance costs can vary when revenue from additional product recovery is included. There is also geographic variability in wellhead prices, which can also influence estimated engineering costs. A $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $180 million in 2008 dollars. The cost estimates for each regulatory option also include reporting and recordkeeping costs of $18,805,398.

As mentioned earlier, the single difference between Option 1 and the proposed Option 2 is the inclusion of RECs for recompletions of existing wells in Option 2. The implication of this inclusion in Option 2 is clear in Table 3-4, as the estimated engineering compliance costs without additional product revenue more than double and VOC emissions reductions also more than double. Meanwhile, the addition of equipment leaks standards in Option 3 increases engineering costs more than $400 million dollars in 2008 dollars, but only marginally increase estimates of emissions reductions of VOCs, methane, and HAPS.

As the price assumption is very influential on estimated impacts, we performed a simple sensitivity analysis of the influence of the assumed wellhead price paid to natural gas producers on the overall engineering costs estimate of the proposed NSPS. Figure 3-1 plots the annualized costs after revenues from natural gas product recovery have been incorporated (in millions of 2008 dollars) as a function of the assumed price of natural gas paid to producers at the wellhead

for the recovered natural gas (represented by the sloped, dotted line). The vertical solid lines in the figure represent the natural gas price assumed in the RIA ($4.00/Mcf) for 2015 and the 2015 forecast by EIA in the 2011 Annual Energy Outlook ($4.22/Mcf) in 2008 dollars.

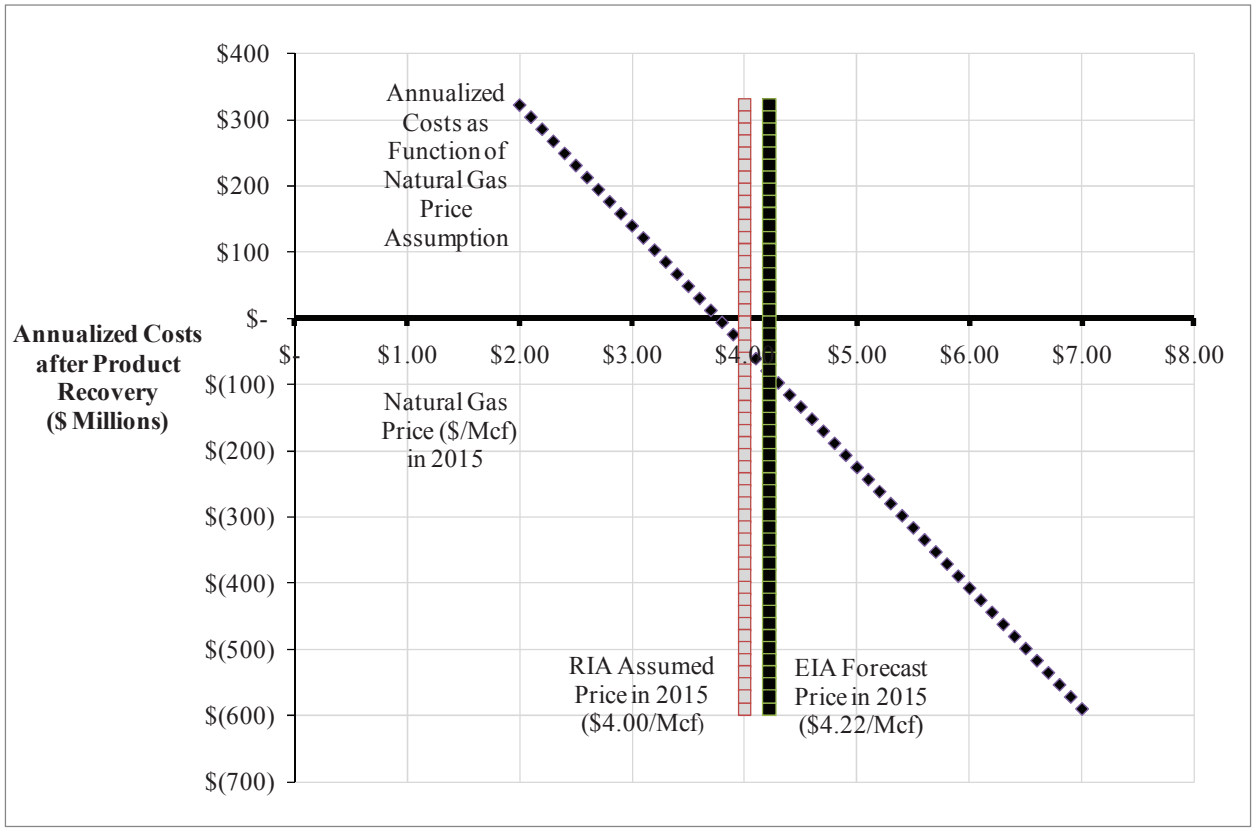


Figure 3-1 Sensitivity Analysis of Proposed NSPS Annualized Costs after Revenues from Additional Product Recovery are Included

As shown in Table 3-4, at the assumed $4/Mcf, the annualized costs are estimated at -$45 million. At $4.22/Mcf, the price forecast reported in the 2011 Annual Energy Outlook, the annualized costs are estimated at about -$90 million, which would approximately double the estimate of net cost savings of the proposed NSPS. As indicated by this difference, EPA has chosen a relatively conservative assumption (leading to an estimate of few savings and higher net costs) for the engineering costs analysis. The natural gas price at which the proposed NSPS breaks-even is around $3.77/Mcf. As mentioned earlier, a $1/Mcf change in the wellhead natural gas price leads to about a $180 million change in the annualized engineering costs of the proposed NSPS. Consequently, annualized engineering costs estimates would increase to about $140 million under a $3/Mcf price or decrease to about -$230 million under a $5/Mcf price.

It is additionally helpful to put the quantity of natural gas and condensate potentially recovered in the context of domestic production levels. To do so, it is necessary to make two adjustments. First, not all emissions reductions can be directed into production streams to be ultimately consumed by final consumers. Several controls require combustion of the natural gas rather than capture and direction into product streams. After adjusting estimates of national emissions reductions in Table 3-3 for these combustion-type controls, Options 1, 2, and 3 are estimated to capture about 83, 183, and 185 bcf of natural gas and 317,000, 726,000, and 726,000 barrels of condensate, respectively. For control options that are expected to recover natural gas products. Estimates of unit-level and nation-level product recovery are presented in Section 3 of the RIA. Note that completion-related requirements for new and existing wells generate all the condensate recovery for all NSPS regulatory options. For natural gas recovery, RECs contribute 77 bcf (92 percent) for Option 1, 176 bcf (97 percent) for Option 2, and 176 bcf (95 percent) for Option 3.

Table 3-5 Estimates of Control Unit-level and National Level Natural Gas and Condensate Recovery, NSPS Options, 2015

Source/ Emissions Points	Emissions Control	NSPS Option	Projected No. of Affected Units	Unit-level Product Recovery		Total Product Recovery	
				Natural Gas Savings (Mcf/unit)	Condensate (bbl/unit)	Natural Gas Savings (Mcf)	Condensate (bbl)
Well Completions							
Hydraulically Fractured Gas Wells	REC	1, 2, 3	9,313	8,258	34	76,905,813	316,657
Hydraulically Fractured Gas Wells	Combustion	1, 2, 3	446	0	0	0	0
Hydraulically Fractured Gas Wells (existing wells)	REC	2, 3	12,050	8,258	34	99,502,875	409,700
Equipment Leaks							
Well Pads	NSPS Subpart VV	3	4,774	386	0	1,840,377	0
Gathering and Boosting Stations	NSPS Subpart VV	3	275	1,472	0	404,869	0
Processing Plants	NSPS Subpart VVa	2, 3	29	2,819	0	81,750	0
Reciprocating Compressors							
Gathering/Boosting Stations	AMM	1, 2, 3	210	397	0	83,370	0
Processing Plants	AMM	1, 2, 3	375	1,079	0	404,677	0
Trans. Compressor Stations	AMM	1, 2, 3	199	1,122	0	223,374	0
Underground Storage Facilities	AMM	1, 2, 3	9	1,130	0	9,609	0
Centrifugal Compressors							
Processing Plants	Dry Seals/Route to Process or Ctrl	1, 2, 3	16	11,527	0	184,435	0
Trans. Compressor Stations	Dry Seals/Route to Process or Ctrl	1, 2, 3	14	5,716	0	80,018	0
Pneumatic Controllers -							
Oil and Gas Production	Low Bleed/Route to Process	1, 2, 3	13,632	386	0	5,254,997	0
Natural Gas Trans. and Storage	Low Bleed/Route to Process	1, 2, 3	67	0	0	0	0
Processing Plants	Instrument Air	1, 2, 3	15	871.0	0	13,064	0
Storage Vessels							
High Throughput	95% control	1, 2, 3	304	146	0	44,189	0
Option 1 Total (Mcf)						**83,203,546**	**316,657**
Option 2 Total (Mcf)						**182,788,172**	**726,357**
Option 3 Total (Mcf)						**185,033,417**	**726,357**

A second adjustment to the natural gas quantities is necessary to account for nonhydrocarbon gases removed and gas that reinjected to repressurize wells, vented or flared, or consumed in production processes. Generally, wellhead production is metered at or near the wellhead and payments to producers are based on these metered values. In most cases, the natural gas is minimally processed at the meter and still contains impurities or co-products that must be processed out of the natural gas at processing plants. This means that the engineering cost estimates of revenues from additional natural gas recovery arising from controls implemented at the wellhead include payment for the impurities, such as the VOC and HAP content of the unprocessed natural gas. According to EIA, in 2009 the gross withdrawal of natural gas totaled 26,013 bcf, but 20,580 bcf was ultimately considered dry production (these figures exclude EIA estimates of flared and vented natural gas). Using these numbers, we apply a factor of 0.79 (20,580 bcf divided by 26,013 bcf) to the adjusted sums in the previous paragraph to estimate the volume of gas that is captured by controls that may ultimately by consumed by final consumers.

After making these adjustments, we estimate that Option 1 will potentially recover approximately 66 bcf, proposed Option 2 will potentially recover about 145 bcf, and Option 3 will potentially recover 146 bcf of natural gas that will ultimately be consumed by natural gas consumers.[7] EIA forecasts that the domestic dry natural gas production in 2015 will be 20,080 bcf. Consequently, Option 1, proposed Option 2, and Option 3 may recover production representing about 0.29 percent, 0.64 percent and 0.65 percent of domestic dry natural gas production predicted in 2015, respectively. These estimates, however, do not account for adjustments producers might make, once compliance costs and potential revenues from additional natural gas recovery factor into economic decisionmaking. Also, as discussed in the previous paragraph, these estimates do not include the nonhydrocarbon gases removed, natural gas reinjected to repressurize wells, and natural gas consumed in production processes, and therefore will be lower than the estimates of the gross natural gas captured by implementing controls.

[7] To convert U.S. short tons of methane to a cubic foot measure, we use the conversion factor of 48.04 Mcf per U.S. short ton.

Clearly, this discussion raises the question as to why, if emissions can be reduced profitably using environmental controls, more producers are not adopting the controls in their own economic self-interest. This question is made clear when examining simple estimates of the rate of return to installing emissions controls that, using the engineering compliance costs estimates, the estimates of natural gas product recovery, and assumed product prices (Table 3-6). The rates of return presented in are for evaluated controls where estimated revenues from additional product recovery exceed the costs. The rate of return is calculated using the simple formula: product recovery, and assumed product prices (Table 3-6). The rates of return presented in are for evaluated controls where estimated revenues from additional product recovery exceed the costs. The rate of return is calculated using the simple formula:

$$\text{rate of return} = \left(\frac{\text{estimated revenues}}{\text{estimated costs}} - 1 \right) \times 100 .$$

Table 3-6 Simple Rate of Return Estimate for NSPS Control Options

Emission Point	Control Option	Rate of Return
New Completions of Hydraulically Fractured Wells	Reduced Emissions Completions	6.5%
Re-completions of Existing Hydraulically Fractured Wells	Reduced Emissions Completions	6.5%
Reciprocating Compressors (Processing Plants)	Replace Packing Every 3 Years of Operation	208.3%
Centrifugal Compressors (Processing Plants)	Convert to Dry Seals	1158.7%
Centrifugal Compressors (Transmission Compressor Stations)	Convert to Dry Seals	726.9%
Pneumatic Controllers (Oil and Gas Production)	Low Bleed	6467.3%
Overall Proposed NSPS	**Low Bleed**	**6.1%**

Note: The table presents only control options where estimated revenues from natural gas product recovery exceeds estimated annualized engineering costs

Recall from Table 2-23 in the Industry Profile, that EIA estimates an industry-level rate of return on investments for various segments of the oil and natural gas industry. While the numbers varies greatly over time because of industry and economic factors, EIA estimates a 10.7 percent rate of return on investments for oil and natural gas production in 2008. While this amount is higher than the 6.5 percent rate estimated for RECs, it is significantly lower than the rate of returns estimated for other controls anticipated to have net savings.

Assuming financially rational producers, standard economic theory suggests that all oil and natural gas firms would incorporate all cost-effective improvements, which they are aware

of, without government intervention. The cost analysis of this draft RIA nevertheless is based on the observation that emission reductions that appear to be profitable in our analysis have not been generally adopted. One possible explanation may be the difference between the average profit margin garnered by productive capital and the environmental capital where the primary motivation for installing environmental capital would be to mitigate the emission of pollutants and confer social benefits as discussed in Chapter 4.

Another explanation for why there appear to be negative cost control technologies that are not generally adopted is imperfect information. If emissions from the oil and natural gas sector are not well understood, firms may underestimate the potential financial returns to capturing emissions. Quantifying emissions is difficult and has been done in relatively few studies. Recently, however, advances in infrared imagery have made it possible to affordably visualize, if not quantify, methane emissions from any source using a handheld camera. This infrared camera has increased awareness within industry and among environmental groups and the public at large about the large number of emissions sources and possible scale of emissions from oil and natural gas production activities. Since, as discussed in the TSD chapter referenced above, 15 percent of new natural gas well completions with hydraulic fracturing and 15 percent of existing natural gas well recompletions with hydraulic fracturing are estimated to be controlled by either flare or REC in the baseline, it is unlikely that a lack of information will be a significant reason for these emission points to not be addressed in the absence of Federal regulation in 2015. However, for other emission points, a lack of information, or the cost associated with doing a feasibility study of potential emission capture technologies, may continue to prevent firms from adopting these improvements in the absence of regulation.

Another explanation is the cost associated with irreversibility associated with implementing these environmental controls are not reflected in the engineering cost estimates above. Due to the high volatility of natural gas prices, it is important to recognize the value of flexibility taken away from firms when requiring them to install and use a particular emissions capture technology. If a firm has not adopted the technology on its own, then a regulation mandating its use means the firm loses the option to postpone investment in the technology in order to pursue alternative investments today, and the option to suspend use of the technology if it becomes unprofitable in the future. Therefore, the full cost of the regulation to the firm is the

engineering cost and the lost option value minus the revenues from the sale of the additional recovered product. In the absence of quantitative estimates of this option value for each emission point affected by the NSPS and NESHAP improvements, the costs presented in this RIA may underestimate the full costs faced by the affected firms. With these caveats in mind, EPA believes it is analytically appropriate to analyze costs and economic impacts costs presented in Table 3-2 and Table 3-3 using the additional product recovery and associated revenues.

3.2.2.2 NESHAP Sources

As discussed in Section 3.2.1.2, EPA examined three emissions points as part of its analysis for the proposed NESHAP amendments. Unlike the controls for the proposed NSPS, the controls evaluated under the proposed NESHAP amendments do not direct significant quantities of natural gas that would otherwise be flared or vented into the production stream. Table 3-7 shows the projected number of controls required, estimated unit-level capital and annualized costs, and estimated total annualized costs. The table also shows estimated emissions reductions for HAPs, VOCs, and methane, as well as a cost-effectiveness estimate for HAP reduction, based upon engineering (not social) costs.

Table 3-7 Summary of Estimated Capital and Annual Costs, Emissions Reductions, and HAP Reduction Cost-Effectiveness for Proposed NESHAP Amendments

Source/Emissions Point	Projected No. of Controls Required	Capital Costs/ Unit (2008$)	Annualized Cost/Unit (2008$)	Total Annualized Cost (2008$)	Emission Reductions (tons per year) HAP	VOC	Methane	HAP Reduction Cost-Effectiveness (2008$/ton)
Production - Small Glycol Dehydrators	115	65,793	30,409	3,497,001	548	893	324	6,377
Transmission - Small Glycol Dehydrators	19	19,537	19,000	361,000	243	475	172	1,483
Storage Vessels	674	65,243	14,528	9,791,872	589	7,812	4,364	16,618
Reporting and Recordkeeping	---	196	2,933	2,369,755	---	---	---	---
Total	**808**			**16,019,871**	**1,381**	**9,243**	**4,859**	**10,576**

Note: Totals may not sum due to independent rounding.

Under the Proposed NESHAP Amendments, about 800 controls will be required, costing a total of $16.0 million (Table 3-7). We include reporting and recordkeeping costs as a unique line item showing these costs for the entire set of proposed amendments. These controls will reduce HAP emissions by about 1,400 tons, VOC emissions by about 9,200 tons, and methane by about 4,859 tons. The cost-per-ton to reduce HAP emissions is estimated at about $11,000 per ton. All figures are in 2008 dollars.

3.3 References

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4 BENEFITS OF EMISSIONS REDUCTIONS

4.1 Introduction

The proposed Oil and Natural Gas NSPS and NESHAP amendments are expected to result in significant reductions in existing emissions and prevent new emissions from expansions of the industry. While we expect that these avoided emissions will result in improvements in air quality and reduce health effects associated with exposure to HAPs, ozone, and fine particulate matter ($PM_{2.5}$), we have determined that quantification of those health benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no health benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. For the proposed NSPS, the HAP and climate benefits can be considered "co-benefits", and for the proposed NESHAP amendments, the ozone and $PM_{2.5}$ health benefits and climate benefits can be considered "co-benefits". These co-benefits occur because the control technologies used to reduce VOC emissions also reduce emissions of HAPs and methane.

The proposed NSPS is anticipated to prevent 37,000 tons of HAPs, 540,000 tons of VOCs, and 3.4 million tons of methane from new sources, while the proposed NESHAP amendments is anticipated reduce 1,400 tons of HAPs, 9,200 tons of VOCs, and 4,900 tons of methane from existing sources. The specific control technologies for the proposed NSPS is also anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 2,800 tons of CO, 7.6 tons of PM, and 1,000 tons of THC, and proposed NESHAP is anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC. Both rules would have additional emission changes associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons for the proposed NSPS and 93 thousand metric tons for the proposed NESHAP. As described in the subsequent sections, these pollutants are associated with substantial health effects, welfare effects, and climate effects. With the data available, we are not able to provide a credible benefits estimates for any of these pollutants for these rules, due to the differences in the locations of oil and natural gas emission points relative to existing information, and the highly localized nature of air quality responses associated with HAP and VOC reductions. In addition, we do not yet have interagency agreed upon valuation estimates

for greenhouse gases other than CO_2 that could be used to value the climate co-benefits associated with avoiding methane emissions. Instead, we provide a qualitative assessment of the benefits and co-benefits as well as a break-even analysis in Chapter 6 of this RIA. A break-even analysis answers the question, "What would the benefits need to be for the benefits to exceed the costs." While a break-even approach is not equivalent to a benefits analysis, we feel the results are illustrative, particularly in the context of previous benefit per ton estimates.

4.2 Direct Emission Reductions from the Oil and Natural Gas Rules

As described in Section 2 of this RIA, oil and natural gas operations in the U.S. include a variety of emission points for VOCs and HAPs including wells, processing plants, compressor stations, storage equipment, and transmission and distribution lines. These emission points are located throughout much of the country with significant concentrations in particular regions. For example, wells and processing plants are largely concentrated in the South Central, Midwest, and Southern California regions of the U.S., whereas gas compression stations are located all over the country. Distribution lines to customers are frequently located within areas of high population density.

In implementing these rules, emission controls may lead to reductions in ambient $PM_{2.5}$ and ozone below the National Ambient Air Quality Standards (NAAQS) in some areas and assist other areas with attaining the NAAQS. Due to the high degree of variability in the responsiveness of ozone and $PM_{2.5}$ formation to VOC emission reductions, we are unable to determine how these rules might affect attainment status without air quality modeling data.[8] Because the NAAQS RIAs also calculate ozone and PM benefits, there are important differences worth noting in the design and analytical objectives of each RIA. The NAAQS RIAs illustrate the potential costs and benefits of attaining a new air quality standard nationwide based on an array of emission control strategies for different sources. In short, NAAQS RIAs hypothesize, but do not predict, the control strategies that States may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. However,

[8] The responsiveness of ozone and $PM_{2.5}$ formation is discussed in greater detail in sections 4.4.1 and 4.5.1 of this RIA.

some costs and benefits estimated in this RIA account for the same air quality improvements as estimated in an illustrative NAAQS RIA.

By contrast, the emission reductions for this rule are from a specific class of well-characterized sources. In general, EPA is more confident in the magnitude and location of the emission reductions for these rules. It is important to note that emission reductions anticipated from these rules do not result in emission increases elsewhere (other than potential energy disbenefits). Emission reductions achieved under these and other promulgated rules will ultimately be reflected in the baseline of future NAAQS analyses, which would reduce the incremental costs and benefits associated with attaining the NAAQS. EPA remains forward looking towards the next iteration of the 5-year review cycle for the NAAQS, and as a result does not issue updated RIAs for existing NAAQS that retroactively update the baseline for NAAQS implementation. For more information on the relationship between the NAAQS and rules such as analyzed here, please see Section 1.2.4 of the SO_2 NAAQS RIA (U.S. EPA, 2010d). Table 4-1 shows the direct emission reductions anticipated for these rules by option. It is important to note that these benefits accrue at different spatial scales. HAP emission reductions reduce exposure to carcinogens and other toxic pollutants primarily near the emission source. Reducing VOC emissions would reduce precursors to secondary formation of $PM_{2.5}$ and ozone, which reduces exposure to these pollutants on a regional scale. Climate effects associated with long-lived greenhouse gases like methane are primarily at a global scale, but methane is also a precursor to ozone, a short-lived climate forcer that exhibits spatial and temporal variability.

Table 4-1 Direct Emission Reductions Associated with Options for the Oil and Natural Gas NSPS and NESHAP amendments in 2015 (short tons per year)

Pollutant	NESHAP Amendments	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3
HAPs	1,381	17,442	36,645	37,142
VOCs	9,243	270,695	535,201	548,449
Methane	4,859	1,574,498	3,386,154	3,442,283

4.3 Secondary Impacts Analysis for Oil and Gas Rules

The control techniques to avert leaks and vents of VOCs and HAPs are associated with several types of secondary impacts, which may partially offset the direct benefits of this rule. In this RIA, we refer to the secondary impacts associated with the specific control techniques as "producer-side" impacts.[9] For example, by combusting VOCs and HAPs, combustion increases emissions of carbon monoxide, NOx, particulate matter and other pollutants. In addition to "producer-side" impacts, these control techniques would also allow additional natural gas recovery, which would contribute to additional combustion of the recovered natural gas and ultimately a shift in the national fuel mix. We refer to the secondary impacts associated with the combustion of the recovered natural gas as "consumer-side" secondary impacts. We provide a conceptual diagram of both categories of secondary impacts in Figure 4-1.

[9] In previous RIAs, we have also referred to these impacts as energy disbenefits.

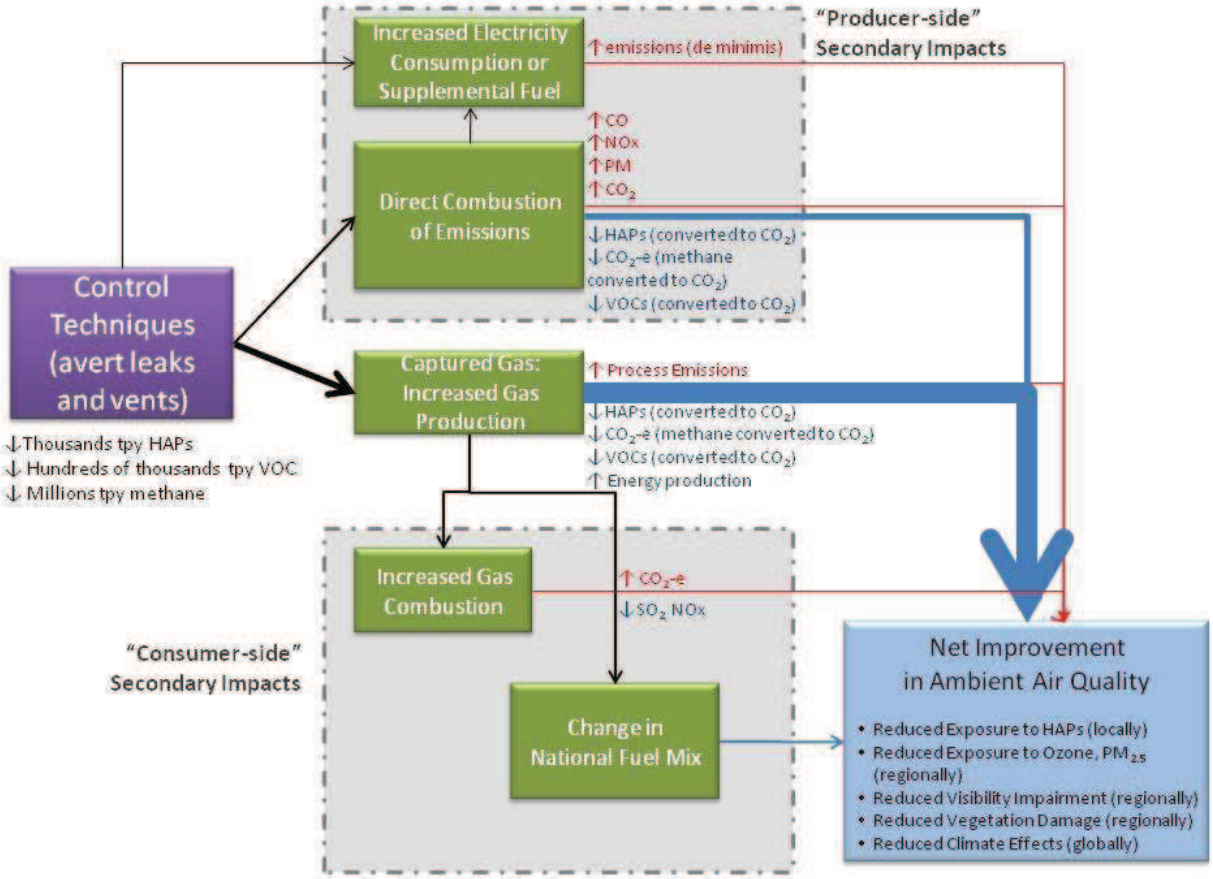


Figure 4-1 Conceptual Diagram of Secondary Impacts from Oil and Gas NSPS and NESHAP Amendments

Table 4-2 shows the estimated secondary impacts for the selected option for the "producer-side" impacts. Relative to the direct emission reductions anticipated from these rules, the magnitude of these secondary air pollutant impacts is small. Because the geographic distribution of these emissions from the oil and gas sector is not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009), we are unable to monetize the $PM_{2.5}$ disbenefits associated with the producer-side secondary impacts. In addition, it is not appropriate to monetize the disbenefits associated with the increased CO_2 emissions without monetizing the averted methane emissions because the overall global warming potential (GWP) is actually

lower. Through the combustion process, methane emissions are converted to CO_2 emissions, which have 21 times less global warming potential compared to methane (IPCC, 2007).[10]

Table 4-2 Secondary Air Pollutant Impacts Associated with Control Techniques by Emissions Category ("Producer-Side") (tons per year)

Emissions Category	CO_2	NOx	PM	CO	THC
Completions of New Wells (NSPS)	587,991	302	5	1,644	622
Recompletions of Existing Wells (NSPS)	398,341	205	-	1,114	422
Pneumatic Controllers (NSPS)	22	1.0	2.6	-	-
Storage Vessels (NSPS)	856	0.5	0.0	2.4	0.9
Total NSPS	**987,210**	**508**	**7.6**	**2,760**	**1,045**
Total NESHAP (Storage Vessels)	**5,543**	**2.9**	**0.1**	**16**	**6**

For the "consumer-side" impacts associated with the NSPS, we modeled the impact of the regulatory options on the national fuel mix and associated CO_2-equivalent emissions (Table 4-3).[11] We provide the modeled results of the "consumer-side" CO_2-equivalent emissions in Table 7-12Error! Reference source not found.

The modeled results indicate that through a slight shift in the national fuel mix, the CO_2-equivalent emissions across the energy sector would increase by 1.6 million metric tons for the proposed NSPS option in 2015. This is in addition to the other secondary impacts and directly avoided emissions, for a total 62 million metric tons of CO_2-equivalent emissions averted as shown in Table 4-4. Due to time limitations under the court-ordered schedule, we did not estimate the other emissions (e.g., NOx, PM, SOx) associated with the additional national gas consumption or the change in the national fuel mix.

[10] This issue is discussed in more detail in Section 4.7 of this RIA.
[11] A full discussion of the energy modeling is available in Section 7 of this RIA.

Table 4-3 Modeled Changes in Energy-related CO_2-equivalent Emissions by Fuel Type for the Proposed Oil and Gas NSPS in 2015 (million metric tons) ("Consumer-Side")[1]

Fuel Type	NSPS Option 1 (million metric tons change in CO_2-e)	NSPS Option 2 (million metric tons change in CO_2-e) (Proposed)	NSPS Option 3 (million metric tons change in CO_2-e)
Petroleum	-0.51	-0.14	-0.18
Natural Gas	2.63	1.35	1.03
Coal	-3.04	0.36	0.42
Other	0.00	0.00	0.00
Total modeled Change in CO_2-e Emissions	**-0.92**	**1.57**	**1.27**

[1] These estimates reflect the modeled change in CO_2-e emissions using NEMS shown in Table 7-12. Totals may not sum due to independent rounding.

Table 4-4 Total Change in CO_2-equivalent Emissions including Secondary Impacts for the Proposed Oil and Gas NSPS in 2015 (million metric tons)

Emissions Source	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP Amendments
Averted CO_2-e Emissions from New Sources[1]	-30.00	-64.51	-65.58	-0.09
Additional CO_2-e Emissions from Combustion and Supplemental Energy (Producer-side)[2]	0.90	0.90	0.90	0.01
Total Modeled Change in Energy-related CO_2-e Emissions (Consumer-side)[3]	-0.92	1.57	1.27	--
Total Change in CO_2-e Emissions after Adjustment for Secondary Impacts	**-30.02**	**-62.04**	**-63.41**	**-0.09**

[1] This estimate reflects the GWP of the avoided methane emissions from new sources shown in Table 4-1 and has been converted from short tons to metric tons.

[2] This estimate represents the secondary producer-side impacts associated with additional CO_2 emissions from combustion and from additional electricity requirements shown in Table 4-2 and has been converted from short tons to metric tons. We use the producer-side secondary impacts associated with the proposed NSPS option as a surrogate for the impacts of the other options.

[3]This estimate reflects the modeled change in the energy–related consumer-side impacts shown in Table 4-3.

Totals may not sum due to independent rounding.

Based on these analyses, the net impact of both the direct and secondary impacts of these rules would be an improvement in ambient air quality, which would reduce exposure to various harmful pollutants, improve visibility impairment, reduce vegetation damage, and reduce potency of greenhouse gas emissions. Table 4-5 provides a summary of the direct and secondary emissions changes for each option.

Table 4-5 Summary of Emissions Changes for the Proposed Oil and Gas NSPS and NESHAP in 2015 (short tons per year)

	Pollutant	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP
Change in Direct Emissions	VOC	-270,000	-540,000	-550,000	-9,200
	Methane	-1,600,000	-3,400,000	-3,400,000	-4,900
	HAP	-17,000	-37,000	-37,000	-1,400
Change in Secondary Emissions (Producer-Side) [1]	CO_2	990,000	990,000	990,000	5,500
	NOx	510	510	510	2.9
	PM	7.6	7.6	7.6	0.1
	CO	2,800	2,800	2,800	16
	THC	1,000	1,000	1,000	6.0
Change in Secondary Emissions (Consumer-Side)	CO_2-e	-1,000,000	1,700,000	1,400,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e	-33,000,000	-68,000,000	-70,000,000	-96,000

[1] We use the producer-side secondary impacts associated with the proposed option as a surrogate for the impacts of the other options. Totals may not sum due to independent rounding.

4.4 Hazardous Air Pollutant (HAP) Benefits

Even though emissions of air toxics from all sources in the U.S. declined by approximately 42 percent since 1990, the 2005 National-Scale Air Toxics Assessment (NATA) predicts that most Americans are exposed to ambient concentrations of air toxics at levels that have the potential to cause adverse health effects (U.S. EPA, 2011d).[12] The levels of air toxics to which people are exposed vary depending on where people live and work and the kinds of activities in which they engage. In order to identify and prioritize air toxics, emission source types and locations that are of greatest potential concern, U.S. EPA conducts the NATA.[13] The most recent NATA was conducted for calendar year 2005 and was released in March 2011. NATA includes four steps:

[12] The 2005 NATA is available on the Internet at http://www.epa.gov/ttn/atw/nata2005/.

[13] The NATA modeling framework has a number of limitations that prevent its use as the sole basis for setting regulatory standards. These limitations and uncertainties are discussed on the 2005 NATA website. Even so, this modeling framework is very useful in identifying air toxic pollutants and sources of greatest concern, setting regulatory priorities, and informing the decision making process. U.S. EPA. (2011) 2005 National-Scale Air Toxics Assessment. http://www.epa.gov/ttn/atw/nata2005/

1) Compiling a national emissions inventory of air toxics emissions from outdoor sources

2) Estimating ambient and exposure concentrations of air toxics across the United States

3) Estimating population exposures across the United States

4) Characterizing potential public health risk due to inhalation of air toxics including both cancer and noncancer effects

Based on the 2005 NATA, EPA estimates that about 5 percent of census tracts nationwide have increased cancer risks greater than 100 in a million. The average national cancer risk is about 50 in a million. Nationwide, the key pollutants that contribute most to the overall cancer risks are formaldehyde and benzene.[14,15] Secondary formation (e.g., formaldehyde forming from other emitted pollutants) was the largest contributor to cancer risks, while stationary, mobile and background sources contribute almost equal portions of the remaining cancer risk.

Noncancer health effects can result from chronic,[16] subchronic,[17] or acute[18] inhalation exposures to air toxics, and include neurological, cardiovascular, liver, kidney, and respiratory effects as well as effects on the immune and reproductive systems. According to the 2005 NATA, about three-fourths of the U.S. population was exposed to an average chronic concentration of air toxics that has the potential for adverse noncancer respiratory health effects. Results from the 2005 NATA indicate that acrolein is the primary driver for noncancer respiratory risk.

[14] Details on EPA's approach to characterization of cancer risks and uncertainties associated with the 2005 NATA risk estimates can be found at http://www.epa.gov/ttn/atw/nata1999/riskbg.html#Z2.

[15] Details about the overall confidence of certainty ranking of the individual pieces of NATA assessments including both quantitative (e.g., model-to-monitor ratios) and qualitative (e.g., quality of data, review of emission inventories) judgments can be found at http://www.epa.gov/ttn/atw/nata/roy/page16.html.

[16] Chronic exposure is defined in the glossary of the Integrated Risk Information (IRIS) database (http://www.epa.gov/iris) as repeated exposure by the oral, dermal, or inhalation route for more than approximately 10% of the life span in humans (more than approximately 90 days to 2 years in typically used laboratory animal species).

[17] Defined in the IRIS database as repeated exposure by the oral, dermal, or inhalation route for more than 30 days, up to approximately 10% of the life span in humans (more than 30 days up to approximately 90 days in typically used laboratory animal species).

[18] Defined in the IRIS database as exposure by the oral, dermal, or inhalation route for 24 hours or less.

Figure 4-2 and Figure 4-3 depict the estimated census tract-level carcinogenic risk and noncancer respiratory hazard from the assessment. It is important to note that large reductions in HAP emissions may not necessarily translate into significant reductions in health risk because toxicity varies by pollutant, and exposures may or may not exceed levels of concern. For example, acetaldehyde mass emissions are more than double acrolein emissions on a national basis, according to EPA's 2005 National Emissions Inventory (NEI). However, the Integrated Risk Information System (IRIS) reference concentration (RfC) for acrolein is considerably lower than that for acetaldehyde, suggesting that acrolein could be potentially more toxic than acetaldehyde.[19] Thus, it is important to account for the toxicity and exposure, as well as the mass of the targeted emissions.

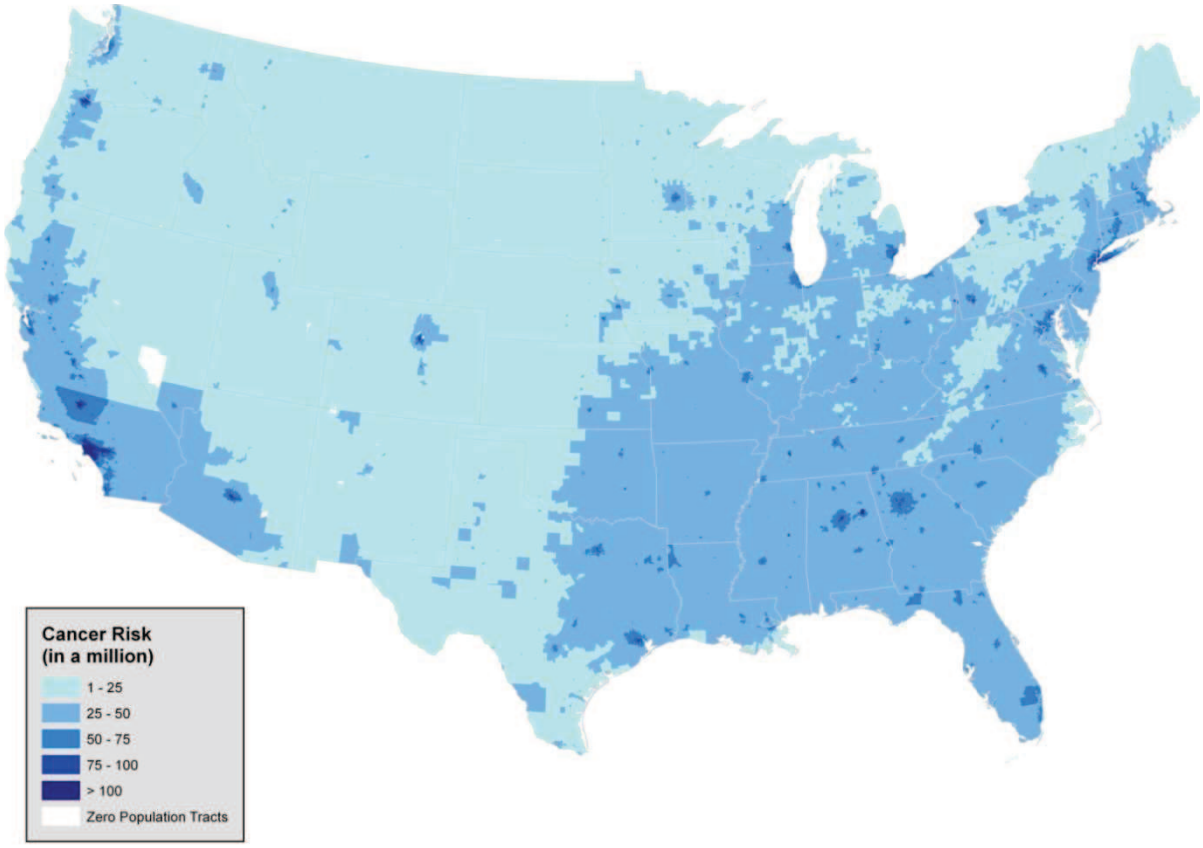


Figure 4-2 Estimated Chronic Census Tract Carcinogenic Risk from HAP exposure from outdoor sources (2005 NATA)

[19] Details on the derivation of IRIS values and available supporting documentation for individual chemicals (as well as chemical values comparisons) can be found at http://cfpub.epa.gov/ncea/iris/compare.cfm.

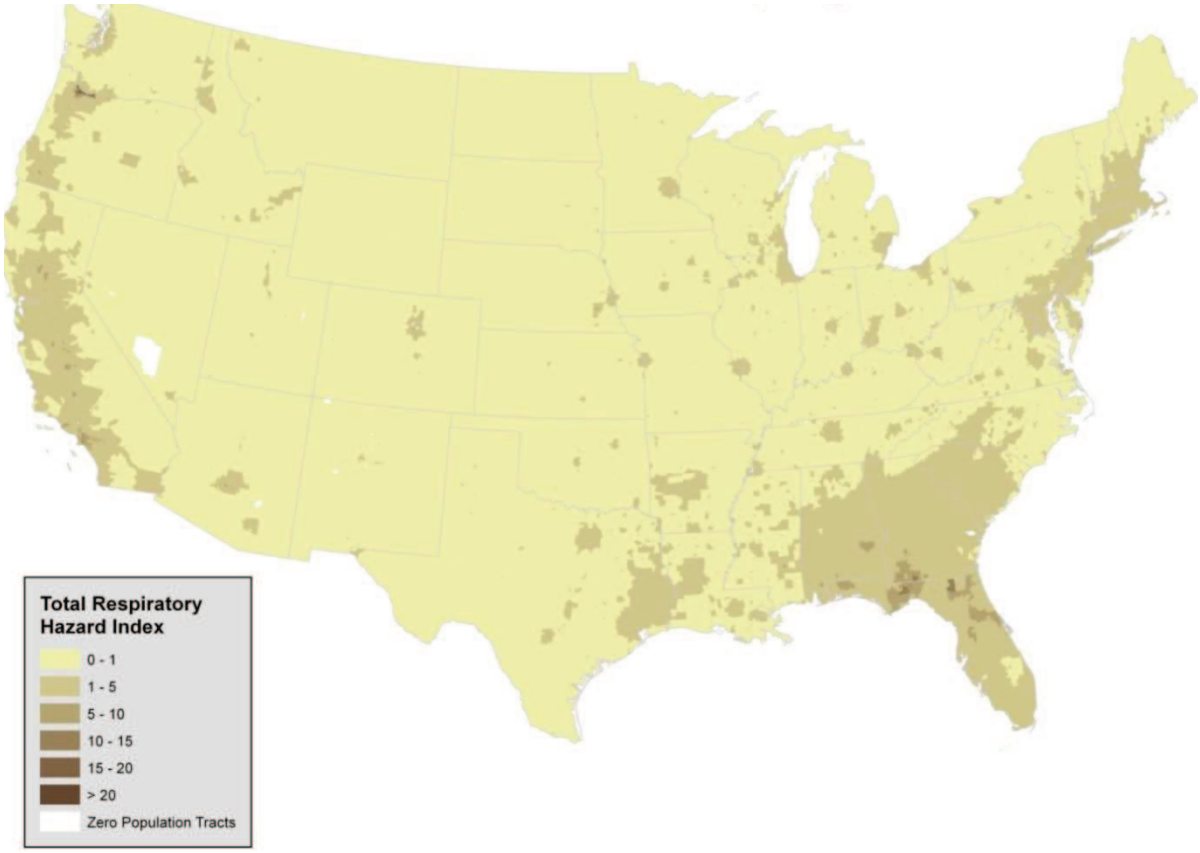


Figure 4-3 Estimated Chronic Census Tract Noncancer (Respiratory) Risk from HAP exposure from outdoor sources (2005 NATA)

Due to methodology and data limitations, we were unable to estimate the benefits associated with the hazardous air pollutants that would be reduced as a result of these rules.. In a few previous analyses of the benefits of reductions in HAPs, EPA has quantified the benefits of potential reductions in the incidences of cancer and non-cancer risk (e.g., U.S. EPA, 1995). In those analyses, EPA relied on unit risk factors (URF) developed through risk assessment procedures.[20] These URFs are designed to be conservative, and as such, are more likely to represent the high end of the distribution of risk rather than a best or most likely estimate of risk. As the purpose of a benefit analysis is to describe the benefits most likely to occur from a reduction in pollution, use of high-end, conservative risk estimates would overestimate the

[20]The unit risk factor is a quantitative estimate of the carcinogenic potency of a pollutant, often expressed as the probability of contracting cancer from a 70-year lifetime continuous exposure to a concentration of one $\mu g/m^3$ of a pollutant.

benefits of the regulation. While we used high-end risk estimates in past analyses, advice from the EPA's Science Advisory Board (SAB) recommended that we avoid using high-end estimates in benefit analyses (U.S. EPA-SAB, 2002). Since this time, EPA has continued to develop better methods for analyzing the benefits of reductions in HAPs.

As part of the second prospective analysis of the benefits and costs of the Clean Air Act (U.S. EPA, 2011a), EPA conducted a case study analysis of the health effects associated with reducing exposure to benzene in Houston from implementation of the Clean Air Act (IEc, 2009). While reviewing the draft report, EPA's Advisory Council on Clean Air Compliance Analysis concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAPs) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (U.S. EPA-SAB, 2008).

In 2009, EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAPs. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn et al., 2011).

In summary, monetization of the benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAPs, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the health benefits of reductions in HAPs in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAPs anticipated to be reduced by these rules and we summarize the results of the residual risk assessment for the Risk and Technology Review (RTR). EPA remains committed to improving methods for estimating HAP benefits by continuing to explore additional concepts of benefits, including changes in the distribution of risk.

Available emissions data show that several different HAPs are emitted from oil and natural gas operations, either from equipment leaks, processing, compressing, transmission and distribution, or storage tanks. Emissions of eight HAPs make up a large percentage the total

HAP emissions by mass from the oil and gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2011a). In the subsequent sections, we describe the health effects associated with the main HAPs of concern from the oil and natural gas sector: benzene, toluene, carbonyl sulfide, ethyl benzene, mixed xylenes, and n-hexane. These rules combined are anticipated to avoid or reduce 58,000 tons of HAPs per year. With the data available, it was not possible to estimate the tons of each individual HAP that would be reduced.

EPA conducted a residual risk assessment for the NESHAP rule (U.S. EPA, 2011c). The results for oil and gas production indicate that maximum lifetime individual cancer risks could be 30 in-a-million for existing sources before and after controls with a cancer incidence of 0.02 before and after controls. For existing natural gas transmission and storage, the maximum individual cancer risk decreases from 90-in-a-million before controls to 20-in-a-million after controls with a cancer incidence that decreases from 0.001 before controls to 0.0002 after controls. Benzene is the primary cancer risk driver. The results also indicate that significant noncancer impacts from existing sources are unlikely, especially after controls. EPA did not conduct a risk assessment for new sources affected by the NSPS. However, it is important to note that the magnitude of the HAP emissions avoided by new sources with the NSPS are more than an order of magnitude higher than the HAP emissions reduced from existing sources with the NESHAP.

4.4.1 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.[21,22,23] EPA states in its IRIS database that data indicate a causal

[21] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0276.htm.

[22] International Agency for Research on Cancer, IARC monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, International Agency for Research on Cancer, World Health Organization, Lyon, France, p. 345-389, 1982.

[23] Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. (1992) Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691-3695.

relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human Services (DHHS) has characterized benzene as a known human carcinogen.[24,25] A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[26,27] The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[28,29] In addition, recent work, including studies sponsored by the Health Effects Institute (HEI), provides evidence that biochemical responses are occurring at lower levels of benzene exposure than previously known.[30,31,32,33] EPA's IRIS program has not yet evaluated these new data.

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[24] International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

[25] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: http://ntp.niehs.nih.gov/go/16183.

[26] Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. Environ. Health Perspect. 82: 193-197.

[27] Goldstein, B.D. (1988). Benzene toxicity. Occupational medicine. State of the Art Reviews. 3: 541-554.

[28] Rothman, N., G.L. Li, M. Dosemeci, W.E. Bechtold, G.E. Marti, Y.Z. Wang, M. Linet, L.Q. Xi, W. Lu, M.T. Smith, N. Titenko-Holland, L.P. Zhang, W. Blot, S.N. Yin, and R.B. Hayes (1996) Hematotoxicity among Chinese workers heavily exposed to benzene. Am. J. Ind. Med. 29: 236-246.

[29] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene (Noncancer Effects). Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: http://www.epa.gov/iris/subst/0276.htm.

[30] Qu, O.; Shore, R.; Li, G.; Jin, X.; Chen, C.L.; Cohen, B.; Melikian, A.; Eastmond, D.; Rappaport, S.; Li, H.; Rupa, D.; Suramaya, R.; Songnian, W.; Huifant, Y.; Meng, M.; Winnik, M.; Kwok, E.; Li, Y.; Mu, R.; Xu, B.; Zhang, X.; Li, K. (2003). HEI Report 115, Validation & Evaluation of Biomarkers in Workers Exposed to Benzene in China.

[31] Qu, Q., R. Shore, G. Li, X. Jin, L.C. Chen, B. Cohen, et al. (2002). Hematological changes among Chinese workers with a broad range of benzene exposures. Am. J. Industr. Med. 42: 275-285.

[32] Lan, Qing, Zhang, L., Li, G., Vermeulen, R., et al. (2004). Hematotoxically in Workers Exposed to Low Levels of Benzene. Science 306: 1774-1776.

[33] Turtletaub, K.W. and Mani, C. (2003). Benzene metabolism in rodents at doses relevant to human exposure from Urban Air. Research Reports Health Effect Inst. Report No.113.

4.4.2 Toluene[34]

Under the 2005 Guidelines for Carcinogen Risk Assessment, there is inadequate information to assess the carcinogenic potential of toluene because studies of humans chronically exposed to toluene are inconclusive, toluene was not carcinogenic in adequate inhalation cancer bioassays of rats and mice exposed for life, and increased incidences of mammary cancer and leukemia were reported in a lifetime rat oral bioassay.

The central nervous system (CNS) is the primary target for toluene toxicity in both humans and animals for acute and chronic exposures. CNS dysfunction (which is often reversible) and narcosis have been frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation: symptoms include fatigue, sleepiness, headaches, and nausea. Central nervous system depression has been reported to occur in chronic abusers exposed to high levels of toluene. Symptoms include ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision. Chronic inhalation exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep.

Human studies have also reported developmental effects, such as CNS dysfunction, attention deficits, and minor craniofacial and limb anomalies, in the children of women who abused toluene during pregnancy. A substantial database examining the effects of toluene in subchronic and chronic occupationally exposed humans exists. The weight of evidence from these studies indicates neurological effects (i.e., impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

4.4.3 Carbonyl sulfide

Limited information is available on the health effects of carbonyl sulfide. Acute (short-term) inhalation of high concentrations of carbonyl sulfide may cause narcotic effects and irritate

[34] All health effects language for this section came from: U.S. EPA. 2005. "Full IRIS Summary for Toluene (CASRN 108-88-3)" Environmental Protection Agency, Integrated Risk Information System (IRIS), Office of Health and Environmental Assessment, Environmental Criteria and Assessment Office, Cincinnati, OH. Available on the Internet at <http://www.epa.gov/iris/subst/0118.htm>.

the eyes and skin in humans.[35] No information is available on the chronic (long-term), reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl sulfide has not undergone a complete evaluation and determination under U.S. EPA's IRIS program for evidence of human carcinogenic potential.[36]

4.4.4 Ethylbenzene

Ethylbenzene is a major industrial chemical produced by alkylation of benzene. The pure chemical is used almost exclusively for styrene production. It is also a constituent of crude petroleum and is found in gasoline and diesel fuels. Acute (short-term) exposure to ethylbenzene in humans results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic (long-term) exposure of humans to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood. Animal studies have reported effects on the blood, liver, and kidneys and endocrine system from chronic inhalation exposure to ethylbenzene. No information is available on the developmental or reproductive effects of ethylbenzene in humans, but animal studies have reported developmental effects, including birth defects in animals exposed via inhalation. Studies in rodents reported increases in the percentage of animals with tumors of the nasal and oral cavities in male and female rats exposed to ethylbenzene via the oral route.[37,38] The reports of these studies lacked detailed information on the incidence of specific tumors, statistical analysis, survival data, and information on historical controls, thus the results of these studies were considered inconclusive by the International Agency for Research on Cancer (IARC, 2000) and the National Toxicology Program (NTP).[39,40] The NTP (1999) carried out a chronic inhalation

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[35] Hazardous Substances Data Bank (HSDB), online database). US National Library of Medicine, Toxicology Data Network, available online at http://toxnet.nlm.nih.gov/. Carbonyl health effects summary available at http://toxnet.nlm.nih.gov/cgi-bin/sis/search/r?dbs+hsdb:@term+@rn+@rel+463-58-1.

[36] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Carbonyl Sulfide. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0617.htm.

[37] Maltoni C, Conti B, Giuliano C and Belpoggi F, 1985. Experimental studies on benzene carcinogenicity at the Bologna Institute of Oncology: Current results and ongoing research. Am J Ind Med 7:415-446.

[38] Maltoni C, Ciliberti A, Pinto C, Soffritti M, Belpoggi F and Menarini L, 1997. Results of long-term experimental carcinogenicity studies of the effects of gasoline, correlated fuels, and major gasoline aromatics on rats. Annals NY Acad Sci 837:15-52.

[39] International Agency for Research on Cancer (IARC), 2000. Monographs on the Evaluation of Carcinogenic Risks to Humans. Some Industrial Chemicals. Vol. 77, p. 227-266. IARC, Lyon, France.

bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in male rats and renal tubule adenoma in females. NTP (1999) also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma in female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies.

4.4.5 Mixed xylenes

Short-term inhalation of mixed xylenes (a mixture of three closely-related compounds) in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects.[41] Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys.[42] Long-term inhalation exposure to xylenes in humans has been associated with a number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination.[43] EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

4.4.6 n-Hexane

The studies available in both humans and animals indicate that the nervous system is the primary target of toxicity upon exposure of n-hexane via inhalation. There are no data in humans and very limited information in animals about the potential effects of n-hexane via the oral route. Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central

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[40] National Toxicology Program (NTP), 1999. Toxicology and Carcinogenesis Studies of Ethylbenzene (CAS No. 100-41-4) in F344/N Rats and in B6C3F1 Mice (Inhalation Studies). Technical Report Series No. 466. NIH Publication No. 99-3956. U.S. Department of Health and Human Services, Public Health Service, National Institutes of Health. NTP, Research Triangle Park, NC.

[41] U.S. Environmental Protection Agency (U.S. EPA). 2003. Integrated Risk Information System File for Mixed Xylenes. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at http://www.epa.gov/iris/subst/0270.htm.

[42] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53.

[43] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53.

nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral effects, neurophysiological changes and neuropathological effects upon inhalation exposure to n-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005), the database for n-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.[44]

4.4.7 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected by these rules, including hydrogen sulfide (H_2S). Information regarding the health effects of those compounds can be found in EPA's IRIS database.[45]

4.5 VOCs

4.5.1 VOCs as a PM2.5 precursor

This rulemaking would reduce emissions of VOCs, which are a precursor to $PM_{2.5}$. Most VOCs emitted are oxidized to carbon dioxide (CO_2) rather than to PM, but a portion of VOC emission contributes to ambient $PM_{2.5}$ levels as organic carbon aerosols (U.S. EPA, 2009a). Therefore, reducing these emissions would reduce $PM_{2.5}$ formation, human exposure to $PM_{2.5}$, and the incidence of $PM_{2.5}$-related health effects. However, we have not quantified the $PM_{2.5}$-related benefits in this analysis. Analysis of organic carbon measurements suggest only a fraction of secondarily formed organic carbon aerosols are of anthropogenic origin. The current state of the science of secondary organic carbon aerosol formation indicates that anthropogenic VOC contribution to secondary organic carbon aerosol is often lower than the biogenic (natural) contribution. Given that a fraction of secondarily formed organic carbon aerosols is from anthropogenic VOC emissions and the extremely small amount of VOC emissions from this sector relative to the entire VOC inventory it is unlikely this sector has a large contribution to

[44] U.S. EPA. 2005. Guidelines for Carcinogen Risk Assessment. EPA/630/P-03/001B. Risk Assessment Forum, Washington, DC. March. Available on the Internet at <http://www.epa.gov/ttn/atw/cancer_guidelines_final_3-25-05.pdf>.

[45] U.S. EPA Integrated Risk Information System (IRIS) database is available at: www.epa.gov/iris

ambient secondary organic carbon aerosols. Photochemical models typically estimate secondary organic carbon from anthropogenic VOC emissions to be less than 0.1 $\mu g/m^3$.

Due to time limitations under the court-ordered schedule, we were unable to perform air quality modeling for this rule. Due to the high degree of variability in the responsiveness of $PM_{2.5}$ formation to VOC emission reductions, we are unable to estimate the effect that reducing VOCs will have on ambient $PM_{2.5}$ levels without air quality modeling.

4.5.2 $PM_{2.5}$ health effects and valuation

Reducing VOC emissions would reduce $PM_{2.5}$ formation, human exposure, and the incidence of $PM_{2.5}$-related health effects. Reducing exposure to $PM_{2.5}$ is associated with significant human health benefits, including avoiding mortality and respiratory morbidity. Researchers have associated $PM_{2.5}$- exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009a). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to $PM_{2.5}$ (e.g., U.S. EPA (2010c)). These health effects include premature mortality for adults and infants, cardiovascular morbidity such as heart attacks, hospital admissions, and respiratory morbidity such as asthma attacks, acute and chronic bronchitis, hospital and ER visits, work loss days, restricted activity days, and respiratory symptoms. Although EPA has not quantified these effects in previous benefits analyses, the scientific literature suggests that exposure to $PM_{2.5}$ is also associated with adverse effects on birth weight, pre-term births, pulmonary function, other cardiovascular effects, and other respiratory effects (U.S. EPA, 2009a).

EPA assumes that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type (U.S. EPA, 2009a). Based on our review of the current body of scientific literature, EPA estimates PM-related mortality without applying an assumed concentration threshold. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels of $PM_{2.5}$ in the underlying epidemiology studies.

Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with effect that those emissions have on ambient $PM_{2.5}$ levels and the health effects associated with $PM_{2.5}$ exposure (Fann, Fulcher, and Hubbell, 2009). Using the estimates in Fann, Fulcher, and Hubbell (2009), the monetized benefit-per-ton of reducing VOC emissions in nine urban areas of the U.S. ranges from $560 in Seattle, WA to $5,700 in San Joaquin, CA, with a national average of $2,400. These estimates assume a 50 percent reduction in VOCs, the Laden et al. (2006) mortality function (based on the Harvard Six City Study, a large cohort epidemiology study in the Eastern U.S.), an analysis year of 2015, and a 3 percent discount rate.

Based on the methodology from Fann, Fulcher, and Hubbell (2009), we converted their estimates to 2008$ and applied EPA's current VSL estimate.[46] After these adjustments, the range of values increases to $680 to $7,000 per ton of VOC reduced for Laden et al. (2006). Using alternate assumptions regarding the relationship between $PM_{2.5}$ exposure and premature mortality from empirical studies and supplied by experts (Pope et al., 2002; Laden et al., 2006; Roman et al., 2008), additional benefit-per-ton estimates are available from this dataset, as shown in Table 4-6. EPA generally presents a range of benefits estimates derived from Pope et al. (2002) to Laden et al. (2006) because they are both well-designed and peer reviewed studies, and EPA provides the benefit estimates derived from expert opinions in Roman et al. (2008) as a characterization of uncertainty. In addition to the range of benefits based on epidemiology studies, this study also provided a range of benefits associated with reducing emissions in eight specific urban areas. The range of VOC benefits that reflects the adjustments as well as the range of epidemiology studies and the range of the urban areas is $280 to $7,000 per ton of VOC reduced.

While these ranges of benefit-per-ton estimates provide useful context for the break-even analysis, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship

[46] For more information regarding EPA's current VSL estimate, please see Section 5.4.4.1 of the RIA for the proposed Federal Transport Rule (U.S. EPA, 2010a). EPA continues to work to update its guidance on valuing mortality risk reductions.

between VOC emissions and $PM_{2.5}$, these factors lead us to conclude that the available VOC benefit per ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

Table 4-6 Monetized Benefits-per-Ton Estimates for VOCs (2008$)

Area	Pope et al.	Laden et al.	Expert A	Expert B	Expert C	Expert D	Expert E	Expert F	Expert G	Expert H	Expert I	Expert J	Expert K	Expert L
Atlanta	$620	$1,500	$1,600	$1,200	$1,200	$860	$2,000	$1,100	$730	$920	$1,200	$980	$250	$940
Chicago	$1,500	$3,800	$4,000	$3,100	$3,000	$2,200	$4,900	$2,800	$1,800	$2,300	$3,000	$2,500	$600	$2,400
Dallas	$300	$740	$780	$610	$590	$420	$960	$540	$360	$450	$590	$480	$120	$460
Denver	$720	$1,800	$1,800	$1,400	$1,400	$1,000	$2,300	$1,300	$850	$1,100	$1,400	$1,100	$280	$850
NYC/ Philadelphia	$2,100	$5,200	$5,500	$4,300	$4,200	$3,000	$6,900	$3,900	$2,500	$3,200	$4,200	$3,400	$830	$3,100
Phoenix	$1,000	$2,500	$2,600	$2,000	$2,000	$1,400	$3,300	$1,800	$1,200	$1,500	$2,000	$1,600	$400	$1,500
Salt Lake	$1,300	$3,100	$3,300	$2,600	$2,500	$1,800	$4,100	$2,300	$1,500	$1,900	$2,500	$2,100	$530	$2,000
San Joaquin	$2,900	$7,000	$7,400	$5,800	$5,600	$4,000	$9,100	$5,200	$3,400	$4,300	$5,600	$4,600	$1,300	$4,400
Seattle	$280	$680	$720	$530	$550	$390	$890	$500	$330	$420	$550	$450	$110	$330
National average	**$1,200**	**$3,000**	**$3,200**	**$2,400**	**$2,400**	**$1,700**	**$3,900**	**$2,200**	**$1,400**	**$1,800**	**$2,400**	**$1,900**	**$490**	**$1,800**

* These estimates assume a 50 percent reduction in VOC emissions, an analysis year of 2015, and a 3 percent discount rate. All estimates are rounded to two significant digits. These estimates have been updated from Fann, Fulcher, and Hubbell (2009) to reflect a more recent currency year and EPA's current VSL estimate. Using a discount rate of 7 percent, the benefit-per-ton estimates would be approximately 9 percent lower. Assuming a 75 percent reduction in VOC emissions would increase the benefit-per-ton estimates by approximately 4 percent to 52 percent. Assuming a 25 percent reduction in VOC emissions would decrease the benefit-per-ton estimates by 5 percent to 52 percent. EPA generally presents a range of benefits estimates derived from Pope et al. (2002) to Laden et al. (2006) and provides the benefits estimates derived from the expert functions from Roman et al. (2008) as a characterization of uncertainty.

4.5.3 Organic PM welfare effects

According to the residual risk assessment for this sector (U.S. EPA, 2011a), persistent and bioaccumulative HAP reported as emissions from oil and gas operations include polycyclic organic matter (POM). POM defines a broad class of compounds that includes the polycyclic aromatic hydrocarbon compounds (PAHs). Several significant ecological effects are associated with deposition of organic particles, including persistent organic pollutants, and PAHs (U.S. EPA, 2009a).

PAHs can accumulate in sediments and bioaccumulate in freshwater, flora, and fauna. The uptake of organics depends on the plant species, site of deposition, physical and chemical properties of the organic compound and prevailing environmental conditions (U.S. EPA, 2009a). PAHs can accumulate to high enough concentrations in some coastal environments to pose an environmental health threat that includes cancer in fish populations, toxicity to organisms living in the sediment and risks to those (e.g., migratory birds) that consume these organisms. Atmospheric deposition of particles is thought to be the major source of PAHs to the sediments of coastal areas of the U.S. Deposition of PM to surfaces in urban settings increases the metal and organic component of storm water runoff. This atmospherically-associated pollutant burden can then be toxic to aquatic biota. The contribution of atmospherically deposited PAHs to aquatic food webs was demonstrated in high elevation mountain lakes with no other anthropogenic contaminant sources.

The recently completed Western Airborne Contaminants Assessment Project (WACAP) is the most comprehensive database on contaminant transport and PM depositional effects on sensitive ecosystems in the Western U.S. (Landers et al., 2008). In this project, the transport, fate, and ecological impacts of anthropogenic contaminants from atmospheric sources were assessed from 2002 to 2007 in seven ecosystem components (air, snow, water, sediment, lichen, conifer needles, and fish) in eight core national parks. The study concluded that bioaccumulation of semi-volatile organic compounds occurred throughout park ecosystems, an elevational gradient in PM deposition exists with greater accumulation in higher altitude areas, and contaminants accumulate in proximity to individual agriculture and industry sources, which is

counter to the original working hypothesis that most of the contaminants would originate from Eastern Europe and Asia.

4.5.4 Visibility Effects

Reducing secondary formation of $PM_{2.5}$ would improve visibility throughout the U.S. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Suspended particles and gases degrade visibility by scattering and absorbing light. Higher visibility impairment levels in the East are due to generally higher concentrations of fine particles, particularly sulfates, and higher average relative humidity levels. Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Previous analyses (U.S. EPA, 2006b; U.S. EPA, 2010c; U.S. EPA, 2011a) show that visibility benefits are a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility related benefits, nor are we able to determine whether VOC emission reductions would be likely to have a significant impact on visibility in urban areas or Class I areas.

4.6 VOCs as an Ozone Precursor

This rulemaking would reduce emissions of VOCs, which are also precursors to secondary formation of ozone. Ozone is not emitted directly into the air, but is created when its two primary components, volatile organic compounds (VOC) and oxides of nitrogen (NOx), combine in the presence of sunlight. In urban areas, compounds representing all classes of VOCs and CO are important compounds for ozone formation, but biogenic VOCs emitted from vegetation tend to be more important compounds in non-urban vegetated areas (U.S. EPA, 2006a). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. However, we have not quantified the ozone-related benefits in this analysis for several reasons. First, previous rules have shown that the monetized benefits associated with reducing ozone exposure are generally smaller than PM-related benefits, even when ozone is the pollutant targeted for control (U.S. EPA, 2010a). Second, the complex non-linear chemistry of ozone formation introduces uncertainty to the development and application of a benefit-per-ton estimate. Third, the impact of reducing VOC

emissions is spatially heterogeneous depending on local air chemistry. Urban areas with a high population concentration are often VOC-limited, which means that ozone is most effectively reduced by lowering VOCs. Rural areas and downwind suburban areas are often NOx-limited, which means that ozone concentrations are most effectively reduced by lowering NOx emissions, rather than lowering emissions of VOCs. Between these areas, ozone is relatively insensitive to marginal changes in both NOx and VOC.

Due to time limitations under the court-ordered schedule, we were unable to perform air quality modeling for this rule. Due to the high degree of variability in the responsiveness of ozone formation to VOC emission reductions, we are unable to estimate the effect that reducing VOCs will have on ambient ozone concentrations without air quality modeling.

4.6.1 Ozone health effects and valuation

Reducing ambient ozone concentrations is associated with significant human health benefits, including mortality and respiratory morbidity (U.S. EPA, 2010a). Epidemiological researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2006c). When adequate data and resources are available, EPA generally quantifies several health effects associated with exposure to ozone (e.g., U.S. EPA, 2010a; U.S. EPA, 2011a). These health effects include respiratory morbidity such as asthma attacks, hospital and emergency department visits, school loss days, as well as premature mortality. Although EPA has not quantified these effects in benefits analyses previously, the scientific literature is suggestive that exposure to ozone is also associated with chronic respiratory damage and premature aging of the lungs.

In a recent EPA analysis, EPA estimated that reducing 15,000 tons of VOCs from industrial boilers resulted in $3.6 to $15 million of monetized benefits from reduced ozone exposure (U.S. EPA, 2011b).[47] This implies a benefit-per-ton for ozone reductions of $240 to $1,000 per ton of VOCs reduced. While these ranges of benefit-per-ton estimates provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in the boiler analysis. Therefore, we do not believe that those

[47] While EPA has estimated the ozone benefits for many scenarios, most of these scenarios also reduce NOx emissions, which make it difficult to isolate the benefits attributable to VOC reductions.

estimates to provide useful estimates of the monetized benefits of these rules, even as a bounding exercise.

4.6.2 Ozone vegetation effects

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2006a). Sensitivity to ozone is highly variable across species, with over 65 plan species identified as "ozone-sensitive", many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects are considered adverse to the public welfare and can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced crop yields, visible foliar injury, reduced plant vigor (e.g., increased susceptibility to harsh weather, disease, insect pest infestation, and competition), species composition shift, and changes in ecosystems and associated ecosystem services.

4.6.3 Ozone climate effects

Ozone is a well-known short-lived climate forcing (SLCF) greenhouse gas (GHG) (U.S. EPA, 2006a). Stratospheric ozone (the upper ozone layer) is beneficial because it protects life on Earth from the sun's harmful ultraviolet (UV) radiation. In contrast, tropospheric ozone (ozone in the lower atmosphere) is a harmful air pollutant that adversely affects human health and the environment and contributes significantly to regional and global climate change. Due to its short atmospheric lifetime, tropospheric ozone concentrations exhibit large spatial and temporal variability (U.S. EPA, 2009b). A recent United Nations Environment Programme (UNEP) study reports that the threefold increase in ground level ozone during the past 100 years makes it the third most important contributor to human contributed climate change behind CO_2 and methane. This discernable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles. This study provides the most comprehensive analysis to date of the benefits of measures to reduce SLCF gases including methane, ozone, and black carbon assessing the health, climate, and agricultural benefits of a suite of mitigation technologies. The report concludes that the climate is changing now, and these changes have the potential to "trigger abrupt transitions such as the release of carbon from thawing permafrost and biodiversity loss" (UNEP 2011). While reducing long-lived GHGs such as CO_2 is necessary to

protect against long-term climate change, reducing SLCF gases including ozone is beneficial and will slow the rate of climate change within the first half of this century (UNEP 2011).

4.7 Methane (CH_4)

4.7.1 Methane as an ozone precursor

This rulemaking would reduce emissions of methane, a long-lived GHG and also a precursor to ozone. In remote areas, methane is a dominant precursor to tropospheric ozone formation (U.S. EPA, 2006a). Unlike NOx and VOCs, which affect ozone concentrations regionally and at hourly time scales, methane emission reductions require several decades for the ozone response to be fully realized, given methane's relatively long atmospheric lifetime (HTAP, 2010). Studies have shown that reducing methane can reduce global background ozone concentrations over several decades, which would benefit both urban and rural areas (West et al., 2006). Therefore, reducing these emissions would reduce ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. The health, welfare, and climate effects associated with ozone are described in the preceding sections. Without air quality modeling, we are unable to estimate the effect that reducing methane will have on ozone concentrations at particular locations.

4.7.2 Methane climate effects and valuation

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that once emitted into the atmosphere absorbs terrestrial infrared radiation which contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone also impacts global temperatures. According to the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (2007), in 2004 the cumulative changes in methane concentrations since preindustrial times contributed about 14 percent to global warming due to anthropogenic GHG sources, making methane the second leading long-lived climate forcer after CO_2 globally. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere which over time leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity, and sea level rise, among other impacts.

Processes in the oil and gas category emit significant amounts of methane. The Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009 (published April 2011) estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 251.55 ($MMtCO_2$-e). In 2009, total methane emissions from the oil and gas industry represented nearly 40 percent of the total methane emissions from all sources and account for about 5 percent of all CO_2-equivalent (CO_2-e) emissions in the U.S., with natural gas systems being the single largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2011b, Table ES-2). It is important to note that the 2009 emissions estimates from well completions and recompletions exclude a significant number of wells completed in tight sand plays and the Marcellus Shale, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays and the Marcellus Shale, and such an adjustment is also being considered as a planned improvement in next year's Inventory. This adjustment would increase the 2009 Inventory estimate by about 80 $MMtCO_2$-e. The total methane emissions from Petroleum and Natural Gas Systems based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus Shale, is approximately 330 $MMtCO_2$-e.

This rulemaking proposes emission control technologies and regulatory alternatives that will significantly decrease methane emissions from the oil and natural gas sector in the United States. The regulatory alternative proposed for this rule is expected to reduce methane emissions annually by about 3.4 million short tons or approximately 65 million metric tons CO_2-e. These reductions represent about 26 percent of the GHG emissions for this sector reported in the 1990-2009 U.S. GHG Inventory (251.55 $MMTCO_2$-e). This annual CO_2-e reduction becomes about 62 million metric tons when the secondary impacts associated with increased combustion and supplemental energy use on the producer side and CO_2-e emissions from changes in consumption patterns previously discussed are considered. However, it is important to note the emissions reductions are based upon predicted activities in 2015; EPA did not forecast sector-level emissions to 2015 for this rulemaking. The climate co-benefit from these reductions are

equivalent of taking approximately 11 million typical passenger cars off the road or eliminating electricity use from about 7 million typical homes each year.[48]

EPA estimates the social benefits of regulatory actions that have a small or "marginal" impact on cumulative global CO_2 emissions using the "social cost of carbon" (SCC). The SCC is an estimate of the net present value of the flow of monetized damages from a one metric ton increase in CO_2 emissions in a given year (or from the alternative perspective, the benefit to society of reducing CO_2 emissions by one ton). The SCC includes (but is not limited to) climate damages due to changes in net agricultural productivity, human health, property damages from flood risk, and ecosystem services due to climate change. The SCC estimates currently used by the Agency were developed through an interagency process that included EPA and other executive branch entities, and concluded in February 2010. The Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 for the final joint EPA/Department of Transportation Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards provides a complete discussion of the methods used to develop the SCC estimates (Interagency Working Group on Social Cost of Carbon, 2010).

To estimate global social benefits of reduced CO_2 emissions, the interagency group selected four SCC values for use in regulatory analyses: $6, $25, $40, and $76 per metric ton of CO_2 emissions in 2015, in 2008 dollars. The first three values are based on the average SCC estimated using three integrated assessment models (IAMs), at discount rates of 5.0, 3.0, and 2.5 percent, respectively. When valuing the impacts of climate change, IAMs couple economic and climate systems into a single model to capture important interactions between the components. SCCs estimated using different discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context. The fourth value is the 95th percentile of the distribution of SCC estimates from all three models at a 3.0 percent discount rate. It is included to represent higher-than-expected damages from temperature change further out in the tails of the SCC distribution.

[48] US Environmental Protection Agency. Greenhouse Gas Equivalency Calculator available at: http://www.epa.gov/cleanenergy/energy-resources/calculator.html accessed 07/19/11.

Although there are relatively few region- or country-specific estimates of SCC in the literature, the results from one model suggest the ratio of domestic to global benefits of emission reductions varies with key parameter assumptions. For example, with a 2.5 or 3 percent discount rate, the U.S. benefit is about 7-10 percent of the global benefit, on average, across the scenarios analyzed. Alternatively, if the fraction of GDP lost due to climate change is assumed to be similar across countries, the domestic benefit would be proportional to the U.S. share of global GDP, which is currently about 23 percent. On the basis of this evidence, values from 7 to 23 percent should be used to adjust the global SCC to calculate domestic effects. It is recognized that these values are approximate, provisional, and highly speculative. There is no a priori reason why domestic benefits should be a constant fraction of net global damages over time. (Interagency Working Group on Social Cost of Carbon, 2010).

The interagency group noted a number of limitations to the SCC analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. The limited amount of research linking climate impacts to economic damages makes estimating damages from climate change even more difficult. The interagency group hopes that over time researchers and modelers will work to fill these gaps and that the SCC estimates used for regulatory analysis by the Federal government will continue to evolve with improvements in modeling. Additional details on these limitations are discussed in the SCC TSD.

A significant limitation of the aforementioned interagency process particularly relevant to this rulemaking is that the social costs of non-CO_2 GHG emissions were not estimated. Specifically, the interagency group did not directly estimate the social cost of non-CO_2 GHGs using the three models. Moreover, the group determined that it would not transform the CO_2 estimates into estimates for non-CO_2 GHGs using global warming potentials (GWPs), which measure the ability of different gases to trap heat in the atmosphere (i.e., radiative forcing per unit of mass) over a particular timeframe relative to CO_2. One potential method for approximating the value of marginal non-CO_2 GHG emission reductions is to convert the reductions to CO_2-equivalents which may then be valued using the SCC. Conversion to CO_2-e is

typically done using the GWPs for the non-CO_2 gas. The GWP is an aggregate measure that approximates the additional energy trapped in the atmosphere over a given timeframe from a perturbation of a non-CO_2 gas relative to CO_2. The time horizon most commonly used is 100 years. One potential problem with utilizing temporally aggregated statistics, such as the GWPs, is that the additional radiative forcing from the GHG perturbation is not constant over time and any differences in temporal dynamics between gases will be lost. This is a potentially confounding issue given that the social cost of GHGs is based on a discounted stream of damages that are non-linear in temperature. For example, methane has an expected adjusted atmospheric lifetime of about 12 years and associated GWP of 21 (IPCC Second Assessment Report (SAR) 100-year GWP estimate). Gases with a shorter lifetime, such as methane, have impacts that occur primarily in the near term and thus are not discounted as heavily as those caused by the longer-lived gases, while the GWP treats additional forcing the same independent of when it occurs in time. Furthermore, the baseline temperature change is lower in the near term and therefore the additional warming from relatively short lived gases will have a lower marginal impact relative to longer lived gases that have an impact further out in the future when baseline warming is higher. The GWP also relies on an arbitrary time horizon and constant concentration scenario. Both of which are inconsistent with the assumptions used by the SCC interagency workgroup. Finally, impacts other than temperature change also vary across gases in ways that are not captured by GWP. For instance, CO_2 emissions, unlike methane will result in CO_2 passive fertilization to plants.

In light of these limitations, and the significant contributions of non-CO_2 emissions to climate change, further analysis is required to link non-CO_2 emissions to economic impacts and to develop social cost estimates for methane specifically. Such work would feed into efforts to develop a monetized value of reductions in methane greenhouse gas emissions in assessing the co-benefits of this rulemaking. As part of ongoing work to further improve the SCC estimates, the interagency group hopes to develop methods to value greenhouse gases other than CO_2, such as methane, by the time SCC estimates for CO_2 emissions are revised.

The EPA recognizes that the methane reductions proposed in this rule will provide significant economic climate co-benefits to society. However, EPA finds itself in the position of

having no interagency accepted monetary values to place on these co-benefits. The 'GWP approach' of converting methane to CO_2-e using the GWP of methane, as previously described, is one approximation method for estimating the monetized value of the methane reductions anticipated from this rule. This calculation uses the GWP of the non-CO_2 gas to estimate CO_2 equivalents and then multiplies these CO_2 equivalent emission reductions by the SCC to generate monetized estimates of the co-benefits. If one makes these calculations for the proposed Option 2 (including expected methane emission reductions from the NESHAP amendments and NSPS and considers secondary impacts) of the oil and gas rule, the 2015 co-benefits vary by discount rate and range from about $373 million to over $4.7 billion; the SCC at the 3 percent discount rate ($25 per metric ton) results in an estimate of $1.6 billion in 2015. These co-benefits equate to a range of approximately $110 to $1,400 per short ton of methane reduced depending upon the discount rate assumed with a per ton estimate of $480 at the 3 percent discount rate

As previously stated, these co-benefit estimates are not the same as would be derived using a directly computed social cost of methane (using the integrated assessment models employed to develop the SCC estimates) for a variety of reasons including the shorter atmospheric lifetime of methane relative to CO_2 (about 12 years compared to CO_2 whose concentrations in the atmosphere decay on timescales of decades to millennia). The climate impacts also differ between the pollutants for reasons other than the radiative forcing profiles and atmospheric lifetimes of these gases. Methane is a precursor to ozone and ozone is a short-lived climate forcer as previously discussed. This use of the SAR GWP to approximate benefits may underestimate the direct radiative forcing benefits of reduced ozone levels, and does not capture any secondary climate co-benefits involved with ozone-ecosystem interactions. In addition, a recent NCEE working paper suggests that this quick 'GWP approach' to benefits estimation will likely understate the climate benefits of methane reductions in most cases (Marten and Newbold, 2011). This conclusion is reached using the 100 year GWP for methane of 25 as put forth in the IPCC Fourth Assessment Report as opposed to the lower value of 21 used in this analysis. Using the higher GWP estimate of 25 would increase these reported methane climate co-benefit estimates by about 19 percent. Although the IPCC Fourth Assessment Report suggested a GWP of 25, EPA has used GWP of 21 consistent with the IPCC SAR to estimate the methane climate co-benefits for this oil and gas proposal. The use of the SAR GWP values allows comparability

of data collected in this proposed rule to the national GHG inventory that EPA compiles annually to meet U.S. commitments to the United Nations Framework Convention on Climate Change (UNFCCC). To comply with international reporting standards under the UNFCCC, official emission estimates are to be reported by the U.S. and other countries using SAR GWP values. The UNFCCC reporting guidelines for national inventories were updated in 2002 but continue to require the use of GWPs from the SAR. The parties to the UNFCCC have also agreed to use GWPs based upon a 100-year time horizon although other time horizon values are available. The SAR GWP value for methane is also currently used to establish GHG reporting requirements as mandated by the GHG Reporting Rule (2010e) and is used by the EPA to determine Title V and Prevention of Significant Deterioration GHG permitting requirements as modified by the GHG Tailoring Rule (2010f).

EPA also undertook a literature search for estimates of the marginal social cost of methane. A range of marginal social cost of methane benefit estimates are available in published literature (Fankhauser (1994), Kandlikar (1995), Hammitt et al. (1996), Tol et al. (2003), Tol, et al. (2006), Hope (2005) and Hope and Newberry (2006). Most of these estimates are based upon modeling assumptions that are dated and inconsistent with the current SCC estimates. Some of these studies focused on marginal methane reductions in the 1990s and early 2000s and report estimates for only the single year of interest specific to the study. The assumptions underlying the social cost of methane estimates available in the literature differ from those agreed upon by the SCC interagency group and in many cases use older versions of the IAMs. Without additional analysis, the methane climate benefit estimates available in the current literature are not acceptable to use to value the methane reductions proposed in this rulemaking.

Due to the uncertainties involved with 'GWP approach' estimates presented and estimates available in the literature, EPA chooses not to compare these co-benefit estimates to the costs of the rule for this proposal. Rather, the EPA presents the 'GWP approach' climate co-benefit estimates as an interim method to produce lower-bound estimates until the interagency group develops values for non-CO_2 GHGs. EPA requests comments from interested parties and the public about this interim approach specifically and more broadly about appropriate methods to monetize the climate co-benefits of methane reductions. In particular, EPA seeks public comments to this proposed rulemaking regarding social cost of methane estimates that may be

used to value the co-benefits of methane emission reductions anticipated for the oil and gas industry from this rule. Comments specific to whether GWP is an acceptable method for generating a placeholder value for the social cost of methane until interagency modeled estimates become available are welcome. Public comments may be provided in the official docket for this proposed rulemaking in accordance with the process outlined in the preamble for the rule. These comments will be considered in developing the final rule for this rulemaking.

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5 STATUTORY AND EXECUTIVE ORDER REVIEWS

5.1 Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, the EPA submitted this action to OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, the EPA prepared a RIA of the potential costs and benefits associated with this action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 5-1 shows the results of the cost and benefits analysis for these proposed rules.

Table 5-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NSPS and NESHAP Amendments in 2015 (millions of 2008$)[1]

	Proposed NSPS	Proposed NESHAP Amendments	Proposed NSPS and NESHAP Amendments Combined
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$45 million	$16 million	-$29 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	37,000 tons of HAPs	1,400 tons of HAPs	38,000 tons of HAPs
	540,000 tons of VOCs	9,200 tons of VOCs	540,000 tons of VOCs
	3.4 million tons of methane	4,900 tons of methane	3.4 million tons of methane
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

5.2 Paperwork Reduction Act

The information collection requirements in this proposed action have been submitted for approval to OMB under the PRA, 44 U.S.C. 3501, et seq. The ICR document prepared by the EPA has been assigned EPA ICR Numbers 1716.07 (40 CFR part 60, subpart OOOO), 1788.10 (40 CFR part 63, subpart HH), 1789.07 (40 CFR part 63, subpart HHH), and 1086.10 (40 CFR part 60, subparts KKK and subpart LLL).

The information to be collected for the proposed NSPS and the proposed NESHAP amendments are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

These proposed rules would require maintenance inspections of the control devices, but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

For sources subject to the proposed NSPS, the burden represents labor hours and costs associated from annual reporting and recordkeeping for each affected facility. The estimated burden is based on the annual expected number of affected operators for the first three years following the effective date of the standards. The burden is estimated to be 560,000 labor hours at a cost of around$18 million per year. This includes the labor and cost estimates previously estimated for sources subject to 40 CFR part 60, subpart KKK and subpart LLL (which is being incorporated into 40 CFR part 60, subpart OOOO). The average hours and cost per regulated entity, which is assumed to be on a per operator basis except for natural gas processing plants (which are estimated on a per facility basis) subject to the NSPS for oil and natural gas production and natural gas transmissions and distribution facilities would be 110 hours per response and $3,693 per response based on an average of 1,459 operators responding per year

and 16 responses per year. The majority of responses are expected to be notifications of construction. One annual report is required that may include all affected facilities owned per each operator. Burden by for the proposed NSPS was based on EPA ICR Number 1716.07.

The estimated recordkeeping and reporting burden after the effective date of the proposed amendments is estimated for all affected major and area sources subject to the oil and natural gas production NESHAP (40 CFR 63, subpart HH) to be approximately 63,000 labor hours per year at a cost of $2.1 million per year. For the natural gas transmission and storage NESHAP, the recordkeeping and reporting burden is estimated to be 2,500 labor hours per year at a cost of $86,800 per year. This estimate includes the cost of reporting, including reading instructions, and information gathering. Recordkeeping cost estimates include reading instructions, planning activities, and conducting compliance monitoring. The average hours and cost per regulated entity subject to the oil and natural gas production NESHAP would be 72 hours per year and $2,500 per year based on an average of 846 facilities per year and three responses per facility. For the natural gas transmission and storage NESHAP, the average hours and cost per regulated entity would be 50 hours per year and $1,600 per year based on an average of 53 facilities per year and three responses per facility. Burden is defined at 5 CFR 1320.3(b). Burden for the oil and natural gas production NESHAP is estimated under EPA ICR Number 1788.10. Burden for the natural gas transmission and storage NESHAP is estimated under EPA ICR Number 1789.07.

5.3 Regulatory Flexibility Act

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises. For purposes of assessing the impact of this rule on small entities, a small entity is defined as: (1) a small business whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a

population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

5.3.1 Proposed NSPS

After considering the economic impact of the Proposed NSPS on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities (SISNOSE). EPA performed a screening analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. Based upon the analysis in Section 7.4 in this RIA, EPA recognizes that a subset of small firms is likely to be significantly impacted by the proposed NSPS. However, the number of significantly impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that the firm-level compliance cost estimates used in the small business impacts analysis are likely over-estimates of the compliance costs faced by firms under the Proposed NSPS; these estimates do not include the revenues that producers are expected receive from the additional natural gas recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from well completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated, if not fully offset. Although this final rule will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities by the selection of highly cost-effective controls and specifying monitoring requirements that are the minimum to insure compliance.

5.3.2 Proposed NESHAP Amendments

After considering the economic impact of the Proposed NESHAP Amendments on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. Based upon the analysis in Section 7.4 in this RIA, we estimate that 62 of the 118 firms (53 percent) that own potentially affected facilities are small entities. EPA performed a screening analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to

revenues. Meanwhile 10 firms (16 percent) are likely to have impacts greater than 1 percent. Four of these 10 firms are likely to have impacts greater than 3 percent. While these 10 firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211. Although this final rule will not impact a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities by setting the final emissions limits at the MACT floor, the least stringent level allowed by law.

5.4 Unfunded Mandates Reform Act

This proposed rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any one year. Thus, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments because it contains no requirements that apply to such governments nor does it impose obligations upon them.

5.5 Executive Order 13132: Federalism

This proposed rule does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this proposed rule.

5.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance

costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement. The EPA has concluded that this proposed rule will not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effect on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

5.7 Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This proposed rule is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is economically significant as defined in Executive Order 12866. However, EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action would not relax the control measures on existing regulated sources. EPA's risk assessments (included in the docket for this proposed rule) demonstrate that the existing regulations are associated with an acceptable level of risk and provide an ample margin of safety to protect public health.

5.8 Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211, (66 FR 28,355, May 22, 2001), provides that agencies shall prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as significant energy actions. Section 4(b) of Executive Order 13211 defines "significant energy actions" as "any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: 1)(i) that is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant

adverse effect on the supply, distribution, or use of energy; or 2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action."

The proposed rules will result in the addition of control equipment and monitoring systems for existing and new sources within the oil and natural gas industry. The proposed NESHAP amendments are unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the proposed NESHAP amendments are not "significant energy actions" as defined in Executive Order 13211, (66 FR 28355, May 22, 2001).

The proposed NSPS is also unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the proposed NSPS is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001). The basis for the determination is as follows.

We use the NEMS to estimate the impacts of the proposed NSPS on the United States energy system. The NEMS is a publically available model of the United States energy economy developed and maintained by the Energy Information Administration of the U.S. DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

Proposed emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One pollution control requirement of the proposed NSPS also captures saleable condensates. The revenues from additional natural gas and condensate recovery are expected to offset the costs of implementing the proposed NSPS.

The analysis of energy impacts for the proposed NSPS that includes the additional product recovery shows that domestic natural gas production is estimated to increase (20 billion cubic feet or 0.1 percent) and natural gas prices to decrease ($0.04/Mcf or 0.9 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. Domestic crude oil production is not estimated to change, while crude oil prices are estimated to decrease slightly ($0.02/barrel or less than 0.1 percent at the wellhead for producers in the lower 48 states) in 2015, the year of analysis. All prices are in 2008 dollars.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden.

5.9 National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law No. 104-113 (15 U.S.C. 272 note) directs the EPA to use VCS in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

The proposed rule involves technical standards. Therefore, the requirements of the NTTAA apply to this action. We are proposing to revise 40 CFR part 63, subparts HH and HHH to allow ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses (Part 10, Instruments and Apparatus) to be used in lieu of EPA Methods 3B, 6 and 16A. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990. Also, we are proposing to revise 40 CFR part 63, subpart HHH, to allow ASTM D6420-99(2004), "Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry" to be used in lieu of EPA Method 18. For a detailed discussion of this VCS, and its appropriateness as a substitute for Method 18, see the final oil and natural gas production NESHAP (Area Sources) (72 FR 36, January 3, 2007).

As a result, the EPA is proposing ASTM D6420-99 for use in 40 CFR part 63, subpart HHH. The EPA also proposes to allow Method 18 as an option in addition to ASTM D6420-99(2004). This would allow the continued use of GC configurations other than GC/MS.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this regulation.

5.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on Environmental Justice (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

To examine the potential for any EJ issues that might be associated with each source category, we evaluated the distributions of HAP-related cancer and noncancer risks across different social, demographic, and economic groups within the populations living near the facilities where these source categories are located. The methods used to conduct demographic analyses for this rule are described in section VII.D of the preamble for this rule. The development of demographic analyses to inform the consideration of EJ issues in EPA rulemakings is an evolving science. The EPA offers the demographic analyses in this proposed rulemaking as examples of how such analyses might be developed to inform such consideration, and invites public comment on the approaches used and the interpretations made from the results, with the hope that this will support the refinement and improve utility of such analyses for future rulemakings.

For the demographic analyses, we focused on the populations within 50 km of any facility estimated to have exposures to HAP which result in cancer risks of 1-in-1 million or greater, or noncancer HI of 1 or greater (based on the emissions of the source category or the facility, respectively). We examined the distributions of those risks across various demographic groups, comparing the percentages of particular demographic groups to the total number of people in those demographic groups nationwide. The results, including other risk metrics, such as average risks for the exposed populations, are documented in source category-specific technical reports in the docket for both source categories covered in this proposal.

As described in the preamble, our risk assessments demonstrate that the regulations for the oil and natural gas production and natural gas transmission and storage source categories, are

associated with an acceptable level of risk and that the proposed additional requirements will provide an ample margin of safety to protect public health.

Our analyses also show that, for these source categories, there is no potential for an adverse environmental effect or human health multi-pathway effects, and that acute and chronic noncancer health impacts are unlikely. The EPA has determined that although there may be an existing disparity in HAP risks from these sources between some demographic groups, no demographic group is exposed to an unacceptable level of risk.

6 COMPARISON OF BENEFITS AND COSTS

Because we are unable to estimate the monetary value of the emissions reductions from the proposed rule, we have chosen to rely upon a break-even analysis to estimate what the monetary value benefits would need to attain in order to equal the costs estimated to be imposed by the rule. A break-even analysis answers the question, "What would the benefits need to be for the benefits to exceed the costs." While a break-even approach is not equivalent to a benefits analysis or even a net benefits analysis, we feel the results are illustrative, particularly in the context of previously modeled benefits.

The total cost of the proposed NSPS in the analysis year of 2015 when the additional natural gas and condensate recovery is included in the analysis is estimated at -$45 million for domestic producers and consumers. EPA anticipates that this rule would prevent 540,000 tons of VOC, 3.4 million tons of methane, and 37,000 tons of HAPs in 2015 from new sources. In 2015, EPA estimates the costs for the NESHAP amendments floor option to be $16 million.[49] EPA anticipates that this rule would reduce 9,200 tons of VOC, 4,900 tons of methane, and 1,400 tons of HAPs in 2015 from existing sources. For the NESHAP amendments, a break-even analysis suggests that HAP emissions would need to be valued at $12,000 per ton for the benefits to exceed the costs if the health benefits, and ecosystem and climate co-benefits from the reductions in VOC and methane emissions are assumed to be zero. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $1,700 per ton or the methane emissions would need to be valued at $3,300 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

For the proposed NSPS, the revenue from additional natural gas recovery already exceeds the costs, which renders a break-even analysis unnecessary. However, as discussed in Section 3.2.2., estimates of the annualized engineering costs that include revenues from natural gas product recovery depend heavily upon assumptions about the price of natural gas and hydrocarbon condensates in analysis year 2015. Therefore, we have also conducted a break-even analysis for the price of natural gas. For the NSPS, a break-even analysis suggests that the price

[49] See Section 3 of this RIA for more information regarding the cost estimates for the NESHAP.

of natural gas would need to be at least $3.77 per Mcf in 2015 for the revenue from product recovery to exceed the annualized costs. EIA forecasts that the price of natural gas would be $4.26 per Mcf in 2015. In addition to the revenue from product recovery, the NSPS would avert emissions of VOCs, HAPs, and methane, which all have value that could be incorporated into the break-even analysis. Figure 6-1 illustrates one method of analyzing the break-even point with alternate natural gas prices and VOC benefits. If, as an illustrative example, the price of natural gas was only $3.00 per Mcf, VOCs would need to be valued at $260 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

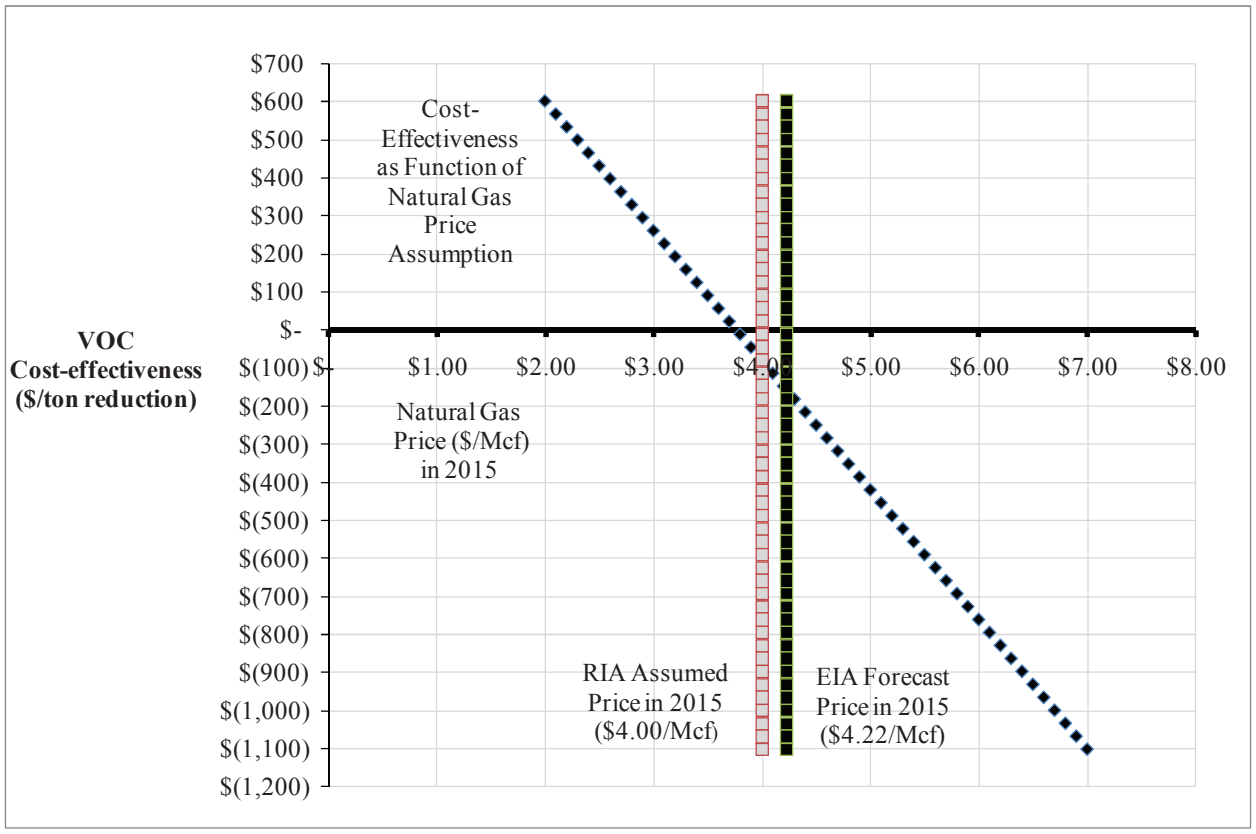


Figure 6-1 Illustrative Break-Even Diagram for Alternate Natural Gas Prices for the NSPS

With the data available, we are not able to provide a credible benefit-per-ton estimate for any of the pollutant reductions for these rules to compare to the break-even estimates. Based on the methodology from Fann, Fulcher, and Hubbell (2009), average $PM_{2.5}$ health-related benefits

of VOC emissions are valued at $280 to $7,000 per ton across a range of eight urban areas.[50] In addition, ozone benefits have been previously valued at $240 to $1,000 per ton of VOC reduced. Using the GWP approach, the climate co-benefits range from approximately $110 to $1,400 per short ton of methane reduced depending upon the discount rate assumed with a per ton estimate of $760 at the 3 percent discount rate.

These break-even benefit-per-ton estimates assume that all other pollutants have zero value. Of course, it is inappropriate to assume that the value of reducing any of these pollutants is zero. Thus, the real break-even estimate is actually lower than the estimates provided above because the other pollutants each have non-zero benefits that should be considered. Furthermore, a single pollutant can have multiple effects (e.g., VOCs contribute to both ozone and $PM_{2.5}$ formation that each have health and welfare effects) that would need to be summed in order to develop a comprehensive estimate of the monetized benefits associated with reducing that pollutant.

As previously described, the revenue from additional natural gas recovery already exceeds the costs of the NSPS, but even if the price of natural gas was only $3.00 per Mcf, it is likely that the VOC benefits would exceed the costs, As a result, even if VOC emissions from oil and natural gas operations result in monetized benefits that are substantially below the average modeled benefits, there is a reasonable chance that the benefits of these rules would exceed the costs, especially if we were able to monetize all of the benefits associated with ozone formation, visibility, HAPs, and methane.

Table 6-1 and Table 6-2 present the summary of the benefits, costs, and net benefits for the NSPS and NESHAP amendment options, respectively. Table 6-3 provides a summary of the direct and secondary emissions changes for each option.

[50] See Section 4.5 of this RIA for more information regarding $PM_{2.5}$ benefits and Section 4.6 for more information regarding ozone benefits.

Table 6-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NSPS in 2015 (millions of 2008$)[1]

	Option 1: Alternative	Option 2: Proposed[4]	Option 3: Alternative
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$19 million	-$45 million	$77 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits	17,000 tons of HAPs[5]	37,000 tons of HAPs[5]	37,000 tons of HAPs[5]
	270,000 tons of VOCs	540,000 tons of VOCs	550,000 tons of VOCs
	1.6 million tons of methane	3.4 million tons of methane	3.4 million tons of methane
	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment	Visibility impairment	Visibility impairment
	Vegetation effects	Vegetation effects	Vegetation effects
	Climate effects[5]	Climate effects[5]	Climate effects[5]

[1] All estimates are for the implementation year (2015) and include estimated revenue from additional natural gas recovery as a result of the NSPS.

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits, including an increase of 990,000 tons of CO_2, 510 tons of NOx, 7.6 tons of PM, 2,800 tons of CO, and 1,000 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 62 million metric tons.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS Options 1 and 2 reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the proposed NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[5] Reduced exposure to HAPs and climate effects are co-benefits.

Table 6-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Proposed Oil and Natural Gas NESHAP amendments in 2015 (millions of 2008$)[1]

	Option 1: Proposed (Floor)
Total Monetized Benefits[2]	N/A
Total Costs[3]	$16 million
Net Benefits	N/A
Non-monetized Benefits	1,400 tons of HAPs
	9,200 tons of VOCs[4]
	4,900 tons of methane[4]
	Health effects of HAP exposure
	Health effects of $PM_{2.5}$ and ozone exposure[4]
	Visibility impairment[4]
	Vegetation effects[4]
	Climate effects[4]

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAPs, ozone, and PM as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. The specific control technologies for the proposed NESHAP are anticipated to have minor secondary disbenefits, including an increase of 5,500 tons of CO_2, 2.9 tons of NOx, 16 tons of CO, and 6.0 tons of THC as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent emission reductions are 93 thousand metric tons.

[3] The cost estimates are assumed to be equivalent to the engineering cost estimates. The engineering compliance costs are annualized using a 7 percent discount rate.

[4] Reduced exposure to VOC emissions, $PM_{2.5}$ and ozone exposure, visibility and vegetation effects, and climate effects are co-benefits.

Table 6-3 Summary of Emissions Changes for the Proposed Oil and Gas NSPS and NESHAP in 2015 (short tons per year)

	Pollutant	NSPS Option 1	NSPS Option 2 (Proposed)	NSPS Option 3	NESHAP
Change in Direct Emissions	VOC	-270,000	-540,000	-550,000	-9,200
	Methane	-1,600,000	-3,400,000	-3,400,000	-4,900
	HAP	-17,000	-37,000	-37,000	-1,400
Change in Secondary Emissions (Producer-Side) [1]	CO_2	990,000	990,000	990,000	5,500
	NOx	510	510	510	2.9
	PM	7.6	7.6	7.6	0.1
	CO	2,800	2,800	2,800	16
	THC	1,000	1,000	1,000	6.0
Change in Secondary Emissions (Consumer-Side)	CO_2-e	-1,000,000	1,700,000	1,400,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e	-33,000,000	-68,000,000	-70,000,000	-96,000

[1] We use the producer-side secondary impacts associated with the proposed NSPS option as a surrogate for the impacts of the other options.

7 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

7.1 Introduction

This section includes three sets of analyses for both the NSPS and NESHAP amendments:

- Energy System Impacts
- Employment Impacts
- Small Business Impacts Analysis

7.2 Energy System Impacts Analysis of Proposed NSPS

We use the National Energy Modeling System (NEMS) to estimate the impacts of the proposed NSPS on the U.S. energy system. The impacts we estimate include changes in drilling activity, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas. We evaluate whether and to what extent the increased production costs imposed by the NSPS might alter the mix of fuels consumed at a national level. With this information we estimate how the changed fuel mix affects national level CO_2-equivalent greenhouse gas emissions from energy sources. We additionally combine these estimates of changes in CO_2-equivalent greenhouse gas emissions from energy sources and emissions co-reductions of methane from the engineering analysis with NEMS analysis to estimate the net change in CO_2-equivalent greenhouse gas emissions from energy-related sources, but this analysis is reserved for the secondary environmental impacts analysis within Section 4.

A brief conceptual discussion about our energy system impacts modeling approach is necessary before going into detail on NEMS, how we implemented the regulatory impacts, and results. Economically, it is possible to view the recovered natural gas as an explicit output or as contributing to an efficiency gain at the producer level. For example, the analysis for the proposed NSPS shows that about 97 percent of the natural gas captured by emissions controls suggested by the rule is captured by performing RECs on new and existing wells that are

completed after being hydraulically fractured. The assumed $4/Mcf price for natural gas is the price paid to producers at the wellhead. In the natural gas industry, production is metered at or very near to the wellhead, and producers are paid based upon this metered production. Depending on the situation, the gas captured by RECs is sent through a temporary or permanent meter. Payments for the gas are typically made within 30 days.

To preview the energy systems modeling using NEMS, results show that after economic adjustments to the new regulations are made by producers, the captured natural gas represents both increased output (a slight increment in aggregate production) and increased efficiency (producing slightly more for less). However, because of differing objectives for the regulatory analysis we treat the associated savings differently in the engineering cost analysis (as an explicit output) and in NEMS (as an efficiency gain).

In the engineering cost analysis, it is necessary to estimate the expected costs and revenues from implementing emissions controls at the unit level. Because of this, we estimate the net costs as expected costs minus expected revenues for representative units. On the other hand, NEMS models the profit maximizing behavior of representative project developers at a drilling project level. The net costs of the regulation alter the expected discounted cash flow of drilling and implementing oil and gas projects, and the behavior of the representative drillers adjusts accordingly. While in the regulatory case natural gas drilling has become more efficient because of the gas recovery, project developers still interact with markets for which supply and demand are simultaneously adjusting. Consequently, project development adjusts to a new equilibrium. While we believe the cost savings as measured by revenues from selling recovered gas (engineering costs) and measured by cost savings from averted production through efficiency gains (energy economic modeling) are approximately the same, it is important to note that the engineering cost analysis and the national-level cost estimates do not incorporate economic feedbacks such as supply and demand adjustments.

7.2.1 Description of the Department of Energy National Energy Modeling System

NEMS is a model of U.S. energy economy developed and maintained by the Energy Information Administration of the U.S. Department of Energy. NEMS is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the energy

economy from the current year to 2035. DOE first developed NEMS in the 1980s, and the model has been undergone frequent updates and expansion since. DOE uses the modeling system extensively to produce issue reports, legislative analyses, and respond to Congressional inquiries.

EIA is legally required to make the NEMS system source code available and fully documented for the public. The source code and accompanying documentation is released annually when a new Annual Energy Outlook is produced. Because of the availability of the NEMS model, numerous agencies, national laboratories, research institutes, and academic and private-sector researchers have used NEMS to analyze a variety of issues.

NEMS models the dynamics of energy markets and their interactions with the broader U.S. economy. The system projects the production of energy resources such as oil, natural gas, coal, and renewable fuels, the conversion of resources through processes such as refining and electricity generation, and the quantity and prices for final consumption across sectors and regions. The dynamics of the energy system are governed by assumptions about energy and environmental policies, technological developments, resource supplies, demography, and macroeconomic conditions. An overview of the model and complete documentation of NEMS can be found at <http://www.eia.doe.gov/oiaf/aeo/overview/index.html>.

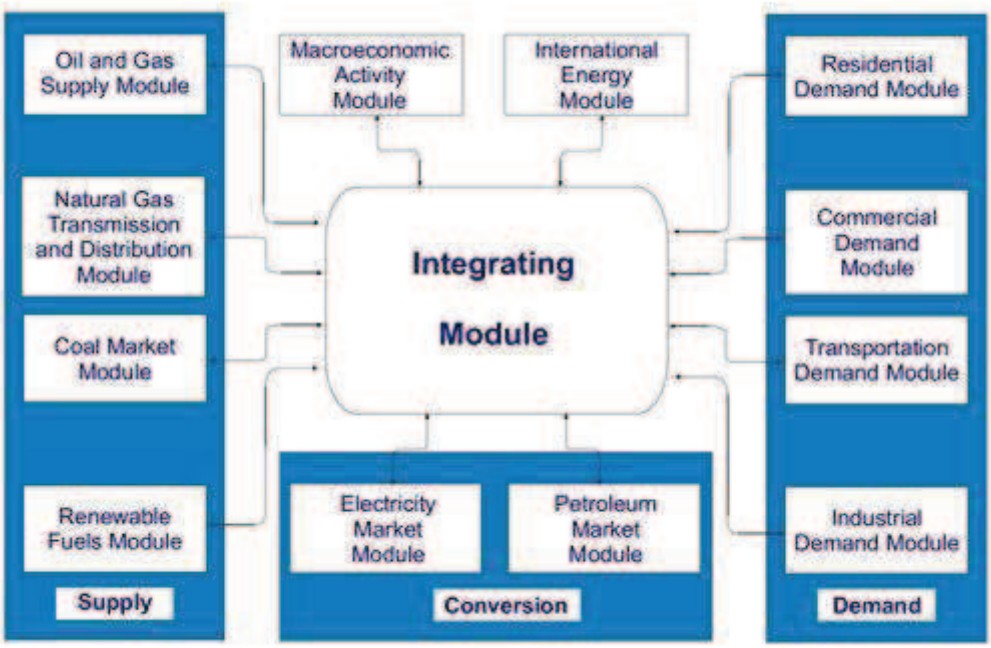


Figure 7-1 Organization of NEMS Modules (source: U.S. Energy Information Administration)

NEMS is a large-scale, deterministic mathematical programming model. NEMS iteratively solves multiple models, linear and non-linear, using nonlinear Gauss-Seidel methods (Gabriel et al. 2001). What this means is that NEMS solves a single module, holding all else constant at provisional solutions, then moves to the next model after establishing an updated provisional solution.

NEMS provides what EIA refers to as "mid-term" projections to the year 2035. However, as this RIA is concerned with estimating regulatory impacts in the first year of full implementation, our analysis focuses upon estimated impacts in the year 2015, with regulatory costs first imposed in 2011. For this RIA, we draw upon the same assumptions and model used in the Annual Energy Outlook 2011.[51] The RIA baseline is consistent with that of the Annual Energy Outlook 2011 which is used extensively in Section 2 in the Industry Profile.

[51] Assumptions for the 2011 Annual Energy Outlook can be found at <http://www.eia.gov/forecasts/aeo/assumptions/index.cfm>.

7.2.2 Inputs to National Energy Modeling System

To model potential impacts associated with the NSPS, we modified oil and gas production costs within the Oil and Gas Supply Module (OGSM) of NEMS and domestic and Canadian natural gas production within the Natural Gas Transmission and Distribution Module (NGTDM). The OGSM projects domestic oil and gas production from onshore, offshore, Alaskan wells, as well as having a smaller-scale treatment of Canadian oil and gas production (U.S. EIA, 2010). The treatment of oil and gas resources is detailed in that oil, shale oil, conventional gas, shale gas, tight sands gas, and coalbed methane (CBM) are explicitly modeled. New exploration and development is pursued in the OGSM if the expected net present value of extracted resources exceeds expected costs, including costs associated with capital, exploration, development, production, and taxes. Detailed technology and reservoir-level production economics govern finding and success rates and costs.

The structure of the OGSM is amenable to analyzing potential impacts of the Oil and Natural Gas NSPS. We are able to target additional expenditures for environmental controls expected to be required by the NSPS on new exploratory and developmental oil and gas production activities, as well as add additional costs to existing projects. We model the impacts of additional environmental costs, as well as the impacts of additional product recovery. We explicitly model the additional natural gas recovered when implementing the NSPS regulatory options. However, we are unable to explicitly model the additional production of condensates expected to be recovered by reduced emissions completions, although we incorporate expected revenues from the condensate recovery in the economic evaluation of new drilling projects.

While the oil production simulated by the OGSM is sent to the refining module (the Petroleum Market Module), simulated natural gas production is sent to a transmission and distribution network captured in the NGTDM. The NGTDM balances gas supplies and prices and "negotiates" supply and consumption to determine a regional equilibrium between supply, demand and prices, including imports and exports via pipeline or LNG. Natural gas transmitted through a simplified arc-node representation of pipeline infrastructure based upon pipeline economics.

7.2.2.1 Compliance Costs for Oil and Gas Exploration and Production

As the NSPS affects new emissions sources, we chose to estimate impacts on new exploration and development projects by adding costs of environmental regulation to the algorithm that evaluates the profitability of new projects. Additional NSPS costs associated with reduced emission completions and future recompletions for new wells are added to drilling, completion, and stimulation costs, as these are, in effect, associated with activities that occur within a single time period, although they may be repeated periodically, as in the case of recompletions. Costs required for reduced emissions recompletions on existing wells are added to stimulation expenses for existing wells exclusively. Other costs are operations and maintenance-type costs and are added to fixed operation and maintenance (O&M) expenses associated with new projects. The one-shot and continuing O&M expenses are estimated and entered on a per well basis, depending on whether the costs would apply to oil wells, natural gas wells, both oil and natural gas wells, or a subset of either. We base the per well cost estimates on the engineering costs including revenues from additional product recovery. This approach is appropriate given the structure of the NEMS algorithm that estimates the net present value of drilling projects.

One concern in basing the regulatory costs inputs into NEMS on the net cost of the compliance activity (estimated annualized cost of compliance minus estimated revenue from product recovery) is that potential barriers to obtaining capital may not be adequately incorporated in the model. However, in general, potential barriers to obtaining additional capital should be reflected in the annualized cost via these barriers increasing the cost of capital. With this in mind, assuming the estimates of capital costs and product recovery are valid, the NEMS results will reflect barriers to obtaining the retired capital. A caveat to this is that the estimated unit-level capital costs of controls which are newly required at a national-level as a result of the proposed regulation—RECs, for example—may not incorporate potential additional transitional costs as the supply of control equipment adjusts to new demand.

Table 7-1 shows the incremental O&M expenses that accrue to new drilling projects as a result of producers having to comply with the relevant NSPS option. We estimate those costs as a function of new wells expected to be drilled in a representative year. To arrive at estimates of

the per well costs, we first identify which emissions reductions will apply primarily to crude oil wells, to natural gas wells, or to both crude oil and natural gas wells. Based on the baseline projections of successful completions in 2015, we used 19,097 new natural gas wells and 12,193 new oil wells as the basis of these calculations. We then divide the estimated compliance costs for the given emissions point (from Table 3-3) by the appropriate number of expected new wells in the year of analysis. The result yields an approximation of a per well compliance costs. We assume this approximation is representative of the incremental cost faced by a producer when evaluating a prospective drilling project.

Like the engineering analysis, we assume that hydraulically fractured well completions and recompletions will be required of wells drilled into tight sand, shale gas, and coalbed methane formations. While costs for well recompletions reflect the cost of a single recompletion, the engineering cost analysis assumed that one in ten new wells drilled after the implementation of the promulgation and implementation of the NSPS are completed using hydraulic fracturing will receive a recompletion in any given year using hydraulic fracturing. Meanwhile, within NEMS, wells are assumed to be stimulated every five years. We assume these more frequent stimulations are less intensive than stimulation using hydraulic fracturing but add costs such that the recompletions costs reflect the same assumptions as the engineering analysis. In entering compliance costs into NEMS, we also account for reduced emissions completions, completion combustion, and recompletions performed in absence of the regulation, using the same assumptions as the engineering costs analysis (Table 7-2).

Table 7-1 Summary of Additional Annualized O&M Costs (on a Per New Well Basis) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Well Costs (2008$)			Wells Applied To in NEMS
		Option 1	Option 2 (Proposed)	Option 3	
Equipment Leaks					
Well Pads	Subpart VV	Not in Option	Not in Option	$3,552	Oil and Gas
Gathering and Boosting Stations	Subpart VV	Not in Option	Not in Option	$806	Gas
Processing Plants	Subpart VVa	Not in Option	$56	$56	None
Transmission Compressor Stations	Subpart VV	Not in Option	Not in Option	$320	Gas
Reciprocating Compressors					
Well Pads	Annual Monitoring/ Maintenance	Not in Option	Not in Option	Not in Option	None
Gathering/Boosting Stations	AMM	$17	$17	$17	Gas
Processing Plants	AMM	$12	$12	$12	Gas
Transmission Compressor Stations	AMM	$19	$19	$19	Gas
Underground Storage Facilities	AMM	$1	$1	$1	Gas
Centrifugal Compressors					
Processing Plants	Dry Seals/Route to Process or Control	-$113	-$113	-$113	Gas
Transmission Compressor Stations	Dry Seals/Route to Process or Control	-$62	-$62	-$62	Gas
Pneumatic Controllers -					
Oil and Gas Production	Low Bleed/Route to Process	-$698	-$698	-$698	Oil and Gas
Natural Gas Transmission and Storage	Low Bleed/Route to Process	$0.10	$0.10	$0.10	Gas
Storage Vessels					
High Throughput	95% control	$143	$143	$143	Oil and Gas
Low Throughput	95% control	Not in Option	Not in Option	Not in Option	None

Table 7-2 Summary of Additional Per Completion/Recompletion Costs (2008$) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Completion/Recompletion Costs (2008$) Option 1	Option 2 (proposed)	Option 3	Wells Applied To in NEMS
Well Completions					
Hydraulically Fractured Gas Wells	REC	-$1,275	-$1,275	-$1,275	New Tight Sand/ Shale Gas/CBM
Conventional Gas Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Oil Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Well Recompletions					
Hydraulically Fractured Gas Wells (post-NSPS wells)	REC	-$1,535	-$1,535	-$1,535	Existing Tight Sand/ Shale Gas /Coalbed Methane
Hydraulically Fractured Gas Wells (existing wells)	REC	Not in Option	-$1,535	-$1,535	Existing Tight Sand/ Shale Gas /Coalbed Methane
Conventional Gas Wells	Combustion	Not in Option	Not in Option	Not in Option	None
Oil Wells	Combustion	Not in Option	Not in Option	Not in Option	None

7.2.2.2 Adding Averted Methane Emissions into Natural Gas Production

A significant benefit of controlling VOC emissions from oil and natural gas production is that methane that would otherwise be lost to the atmosphere can be directed into the natural gas production stream. We chose to model methane capture in NEMS as an increase in natural gas industry productivity, ensuring that, within the model, natural gas reservoirs are not decremented by production gains from methane capture. We add estimates of the quantities of methane captured (or otherwise not vented or combusted) to the base quantities that the OGSM model supplies to the NGTDM model. We subdivide the estimates of commercially valuable averted emissions by region and well type in order to more accurately portray the economics of implementing the environmental technology. Adding the averted methane emissions in this manner has the effect of moving the natural gas supply curve to the right an increment consistent with the technically achievable emissions transferred into the production stream as a result of the proposed NSPS.

For all control options, with the exception of recompletions on existing wells, we enter the increased natural gas recovery into NEMS on a per-well basis for new wells, following an

estimation procedure similar to that of entering compliance costs into NEMS on a per well basis for new wells. Because each NSPS Option is composed of a different suite of emissions controls, the per-well natural gas recovery value for new wells is different across wells. For Option 1, we estimate that natural gas recovery is 5,739 Mcf per well. For Option 2 and Option 3, we estimate that natural gas recovery is 5,743 Mcf per well. We make a simplifying assumption that natural gas recovery accruing to new wells accrues to new wells in shale gas, tight sands, and CBM fields. We make these assumptions because new wells in these fields are more likely to satisfy criteria such that RECs are required, which contributed that large majority of potential natural gas recovery. Note that these per well natural gas recovery is lower than the per well estimate when RECs are implemented. The estimate is lower because we account for emissions that are combusted, RECs that are implemented absent Federal regulation, as well as the likelihood that natural gas is used during processing and transmission or reinjected.

We treat the potential natural gas recovery associated with recompletions of existing wells (in proposed Option 2 and Option 3) differently in that we estimated the natural gas recovery by natural gas resource type and NSPS Option based on a combination of the engineering analysis and production patterns from the 2011 Annual Energy Outlook. We estimate that additional natural gas product recovered by recompleting existing wells in proposed Option 2 and Option 3 to be 78.7 bcf, with 38.4 bcf accruing to shale gas, 31.4 bcf accruing to tight sands, and 8.9 bcf accruing to CBM, respectively. This quantity is distributed within the NGTDM to reflect regional production by resource type.

7.2.2.3 Fixing Canadian Drilling Costs to Baseline Path

Domestic drilling costs serve as a proxy for Canadian drilling costs in the Canadian oil and natural gas sub-model within the NGTDM. This implies that, without additional modification, additional costs imposed by a U.S. regulation will also impact drilling decisions in Canada. Changes in international oil and gas trade are important in the analysis, as a large majority of natural gas imported into the U.S. originates in Canada. To avoid this problem, we fixed Canadian drilling costs using U.S. drilling costs from the baseline scenario. This solution enables a more accurate analysis of U.S.-Canada energy trade, as increased drilling costs in the U.S. as a result of environmental regulation serve to increase Canada's comparative advantage.

7.2.3 Energy System Impacts

As mentioned earlier, we estimate impacts to drilling activity, reserves, price and quantity changes in the production and consumption of crude oil and natural gas, and changes in international trade of crude oil and natural gas, as well as whether and to what extent the NSPS might alter the mix of fuels consumed at a national level. In each of these estimates, we present estimates for the baseline year of 2015 and results for the three NSPS options. For context, we provide estimates of production activities in 2011.

7.2.3.1 Impacts on Drilling Activities

Because the potential costs of the NSPS options are concentrated in production activities, we first report estimates of impacts on crude oil and natural gas drilling activities and production and price changes at the wellhead. Table 7-3 presents estimates of successful wells drilled in the U.S. in 2015, the analysis year, for the three NSPS options and in the baseline.

Table 7-3 Successful Oil and Gas Wells Drilled, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Successful Wells Drilled					
Natural Gas	16,373	19,097	19,191	18,935	18,872
Crude Oil	10,352	11,025	11,025	11,025	11,028
Total	**26,725**	**30,122**	**30,216**	**29,960**	**29,900**
% Change in Successful Wells Drilled from Baseline					
Natural Gas			0.49%	-0.85%	-1.18%
Crude Oil			0.00%	0.00%	0.03%
Total			**0.31%**	**-0.54%**	**-0.74%**

We estimate that the number of successful natural gas wells drilled increases slightly for Option 1, while the number of successful crude oil wells drilled does not change. In Options 2, where costs of the natural gas processing plants equipment leaks standard and REC requirements for existing wells apply, natural gas wells drilling is forecast to decrease less than 1 percent, while crude oil drilling does not change. For Option 3, where the addition of an additional equipment

leak standards add to the incremental costs, natural gas well drilling is estimated to decrease about 1.2%. The number of successful crude oil wells drilled under Option 3 increases very slightly. While it may seem counter-intuitive that the number of successful crude wells increased as costs increase, it is important to note that crude oil and natural gas drilling compete with each other for factors of production, such as labor and material. The environmental compliance costs of the NSPS options predominantly affect natural gas drilling. As natural gas drilling declines, for example, as a result of increased compliance costs, crude oil drilling may increase because of the increased availability of labor and material, as well as the likelihood that crude oil can substitute for natural gas to some extent.

Table 7-4 presents the forecast of successful wells by well type, for onshore drilling in the lower 48 states. The results show that conventional well drilling is unaffected by the regulatory options, as reduced emission completion and completion combustion requirements are directed not toward wells in conventional reserves but toward wells that are hydraulically fractured, the wells in so-called unconventional reserves. The impacts on drilling tight sands, shale gas, and coalbed methane vary by option.

Table 7-4 Successful Wells Drilled by Well Type (Onshore, Lower 48 States), NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Successful Wells Drilled					
Conventional Gas Wells	7,267	7,607	7,607	7,607	7,607
Tight Sands	2,441	2,772	2,791	2,816	2,780
Shale Gas	5,007	7,022	7,074	6,763	6,771
Coalbed Methane	1,593	1,609	1,632	1,662	1,627
Total	**16,308**	**19,010**	**19,104**	**18,849**	**18,785**
% Change in Successful Wells Drilled from Baseline					
Conventional Gas Wells			0.00%	0.00%	0.00%
Tight Sands			0.70%	1.60%	0.29%
Shale Gas			0.74%	-3.68%	-3.57%
Coalbed Methane			1.44%	3.28%	1.09%
Total			**0.50%**	**-0.85%**	**-1.18%**

Well drilling in tight sands is estimated to increase slightly from the baseline under all three options, 0.70 percent, 1.60 percent, and 0.29% for Options 1, 2, and 3, respectively. Wells in CBM reserves are also estimated to increase from the baseline under all three options, or 1.44 percent, 3.28 percent, and 1.09 percent for Options 1, 2, and 3, respectively. However, drilling in shale gas is forecast to decline from the baseline under Options 2 and 3, by 3.68 percent and 3.57 percent, respectively.

7.2.3.2 Impacts on Production, Prices, and Consumption

Table 7-5 shows estimates of the changes in the domestic production of natural gas and crude oil under the NSPS options, as of 2015. Domestic crude oil production is not forecast to change under any of the three regulatory options, again because impacts on crude oil drilling of the NSPS are expected to be negligible.

Table 7-5 Annual Domestic Natural Gas and Crude Oil Production, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Domestic Production					
Natural Gas (trillion cubic feet)	21.05	22.43	22.47	22.45	22.44
Crude Oil (million barrels/day)	5.46	5.81	5.81	5.81	5.81
% Change in Domestic Production from Baseline					
Natural Gas			0.18%	0.09%	0.04%
Crude Oil			0.00%	0.00%	0.00%

Natural gas production, on the other hand, increases under all three regulatory options for the NSPS from the baseline. A main driver for these increases is the additional natural gas recovery engendered by the control requirements. Another driver for the increases under Option 1 is the increase in natural gas well drilling. While we showed earlier that natural gas drilling is estimated to decline under Options 2 and 3, the increased natural gas recovery is sufficient to offset the production loss from relatively fewer producing wells.

For the proposed option, the NEMS analysis shown in Table 7-5 estimates a 20 bcf increase in domestic natural gas production. This amount is less than the amount estimated in the engineering analysis to be captured by emissions controls implemented as a result of the

proposed NSPS (approximately 180 bcf). This difference is because NEMS models the adjustment of energy markets to the now relatively more efficient natural gas production sector. At the new natural gas supply and demand equilibrium in 2015, the modeling estimates 20 bcf more gas is produced at a relatively lower wellhead price (which will be presented momentarily). However, at the new equilibrium, producers implementing emissions controls still capture and sell approximately 180 bcf of natural gas. For example, as shown in Table 7-4, about 11,200 new unconventional natural gas wells are completed under the proposed NSPS; using assumptions from the engineering cost analysis about RECs required under State regulations and exploratory wells exempted from REC requirements, about 9,000 NSPS-required RECs would be performed on new natural gas well completions, according to the NEMS analysis. This recovered natural gas substitutes for natural gas that would be produced from the ground absent the rule. In effect, then, about 160 bcf of natural gas that would have been extracted and emitted into the atmosphere is left in the formation for future extraction.

As we showed for natural gas drilling, Table 7-6 shows natural gas production from onshore wells in the lower 48 states by type of well, predicted for 2015, the analysis year. Production from conventional natural gas wells and CBM wells are estimated to increase under all NSPS regulatory options. Production from shale gas reserves is estimated to decrease under Options 2 and 3, however, from the baseline projection. Production from tight sands is forecast to decline slightly under Option 1.

Table 7-6 Natural Gas Production by Well Type (Onshore, Lower 48 States), NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Natural Gas Production by Well Type (trillion cubic feet)					
Conventional Gas Wells	4.06	3.74	3.75	3.76	3.76
Tight Sands	5.96	5.89	5.87	6.00	6.00
Shale Gas	5.21	7.20	7.26	7.06	7.06
Coalbed Methane	1.72	1.67	1.69	1.72	1.71
Total	**16.95**	**18.51**	**18.57**	**18.54**	**18.53**
% Change in Natural Gas Production by Well Type from Baseline					
Conventional Gas Wells			0.32%	0.42%	0.48%
Tight Sands			-0.43%	1.82%	1.72%
Shale Gas			0.73%	-1.97%	-1.93%
Coalbed Methane			1.07%	2.86%	2.60%
Total			0.31%	0.16%	0.13%

Note: Totals may not sum due to independent rounding.

Overall, of the regulatory options, the proposed Option 2 is estimated to have the highest natural gas production from onshore wells in the lower 48 states, showing a 1.2% increase over the baseline projection.

Table 7-7 presents estimates of national average wellhead natural gas and crude oil prices for onshore production in the lower 48 states, estimated for 2015, the year of analysis. All NSPS options show a decrease in wellhead natural gas and crude oil prices. The decrease in wellhead natural gas price form the baseline is attributable largely to the increased productivity of natural gas wells as a result of capturing a portion of completion emissions (in Options 1, 2, and 3) and in capturing recompletion emissions (in Options 2 and 3).

Table 7-7 Lower 48 Average Natural Gas and Crude Oil Wellhead Price, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Lower 48 Average Wellhead Price					
Natural Gas (2008$ per Mcf)	4.07	4.22	4.18	4.18	4.19
Crude Oil (2008$ per barrel)	83.65	94.60	94.59	94.58	94.58
% Change in Lower 48 Average Wellhead Price from Baseline					
Natural Gas			-0.94%	-0.94%	-0.71%
Crude Oil			-0.01%	-0.02%	-0.02%

Table 7-8 presents estimates of the price of natural gas to final consumers in 2008 dollars per million BTU. The production price decreases estimated across NSPS are largely passed on to consumers but distributed unequally across consuming sectors. Electric power sector consumers of natural gas are estimated to receive the largest price decrease while the transportation and residential sectors are forecast to receive the smallest price decreases.

Table 7-8 Delivered Natural Gas Prices by Sector (2008$ per million BTU), 2015, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Delivered Prices (2008$ per million BTU)					
Residential	10.52	10.35	10.32	10.32	10.33
Commercial	9.26	8.56	8.52	8.53	8.54
Industrial	4.97	5.08	5.05	5.05	5.06
Electric Power	4.81	4.77	4.73	4.74	4.75
Transportation	12.30	12.24	12.20	12.22	12.22
Average	**6.76**	**6.59**	**6.55**	**6.57**	**6.57**
% Change in Delivered Prices from Baseline					
Residential			**-0.29%**	**-0.29%**	**-0.19%**
Commercial			**-0.47%**	**-0.35%**	**-0.23%**
Industrial			**-0.59%**	**-0.59%**	**-0.39%**
Electric Power			**-0.84%**	**-0.63%**	**-0.42%**
Transportation			**-0.33%**	**-0.16%**	**-0.16%**
Average			**-0.60%**	**-0.41%**	**-0.30%**

Final consumption of natural gas is also estimated to increase in 2015 from the baseline under all NSPS options, as is shown on Table 7-9. Like delivered price, the consumption shifts are distributed differently across sectors.

Table 7-9 Natural Gas Consumption by Sector, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Consumption (trillion cubic feet)					
Residential	4.76	4.81	4.81	4.81	4.81
Commercial	3.22	3.38	3.38	3.38	3.38
Industrial	6.95	8.05	8.06	8.06	8.06
Electric Power	7.00	6.98	7.00	6.98	6.97
Transportation	0.03	0.04	0.04	0.04	0.04
Pipeline Fuel	0.64	0.65	0.65	0.66	0.66
Lease and Plant Fuel	1.27	1.20	1.21	1.21	1.21
Total	**23.86**	**25.11**	**25.15**	**25.14**	**25.13**
% Change in Consumption from Baseline					
Residential			0.00%	0.00%	0.00%
Commercial			0.00%	0.00%	0.00%
Industrial			0.12%	0.12%	0.12%
Electric Power			0.29%	0.00%	-0.14%
Transportation			0.00%	0.00%	0.00%
Pipeline Fuel			0.00%	1.54%	1.54%
Lease and Plant Fuel			0.83%	0.83%	0.83%
Total			**0.16%**	**0.12%**	**0.08%**

Note: Totals may not sum due to independent rounding.

7.2.3.3 Impacts on Imports and National Fuel Mix

The NEMS modeling shows that impacts from all NSPS options are not sufficiently large to affect the trade balance of natural gas. As shown in Table 7-10, estimates of crude oil and natural gas imports do not vary from the baseline in 2015 for each regulatory option.

Table 7-10 Net Imports of Natural Gas and Crude Oil, NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Net Imports					
Natural Gas (trillion cubic feet)	2.75	2.69	2.69	2.69	2.69
Crude Oil (million barrels/day)	9.13	8.70	8.70	8.70	8.70
% Change in Net Imports					
Natural Gas			0.00%	0.00%	0.00%
Crude Oil			0.00%	0.00%	0.00%

Table 7-11 evaluates estimates of energy consumption by energy type at the national level for 2015, the year of analysis. All three NSPS options are estimated to have small effects at the national level. For Option 1, we estimate an increase in 0.02 quadrillion BTU in 2015, a 0.02 percent increase. The percent contribution of natural gas and biomass is projected to increase, while the percent contribution of liquid fuels and coal is expected to decrease under Option 1. Meanwhile, under the proposed Options 2, total energy consumption is also forecast to rise 0.02 quadrillion BTU, with increase coming from natural gas primarily, with an additional small increase in coal consumption. Under Option 3, total energy consumption is forecast to rise 0.01 quadrillion BTU, or 0.01%, with a slight decrease in liquid fuel consumption from the baseline, but increases in natural gas and coal consumption.

Table 7-11 Total Energy Consumption by Energy Type (Quadrillion BTU), NSPS Options

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Consumption (quadrillion BTU)					
Liquid Fuels	37.41	39.10	39.09	39.10	39.09
Natural gas	24.49	25.77	25.82	25.79	25.79
Coal	20.42	19.73	19.71	19.74	19.74
Nuclear Power	8.40	8.77	8.77	8.77	8.77
Hydropower	2.58	2.92	2.92	2.92	2.92
Biomass	2.98	3.27	3.28	3.27	3.27
Other Renewable Energy	1.72	2.14	2.14	2.14	2.14
Other	0.30	0.31	0.31	0.31	0.31
Total	**98.29**	**102.02**	**102.04**	**102.04**	**102.03**
% Change in Consumption from Baseline					
Liquid Fuels			-0.03%	0.00%	-0.03%
Natural Gas			0.19%	0.08%	0.08%
Coal			-0.10%	0.05%	0.05%
Nuclear Power			0.00%	0.00%	0.00%
Hydropower			0.00%	0.00%	0.00%
Biomass			0.31%	0.00%	0.00%
Other Renewable Energy			0.00%	0.00%	0.00%
Other			0.00%	0.00%	0.00%
Total			**0.02%**	**0.02%**	**0.01%**

Note: Totals may not sum due to independent rounding.

With the national profile of energy consumption estimated to change slightly under the regulatory options in 2015, the year of analysis, it is important to examine whether aggregate energy-related CO_2-equivalent greenhouse gas (GHG) emissions also shift. A more detailed discussion of changes in CO_2-equivalent GHG emissions from a baseline is presented within the benefits analysis in Section 4. Here, we present a single NEMS-based table showing estimated changes in energy-related "consumer-side" GHG emissions. We use the terms "consumer-side" emissions to distinguish emissions from the consumption of fuel from emissions specifically associated with the extraction, processing, and transportation of fuels in the oil and natural gas sector under examination in this RIA. We term the emissions associated with extraction, processing, and transportation of fuels "producer-side" emissions.

Table 7-12 Modeled Change in Energy-related "Consumer-Side" CO_2-equivalent GHG Emissions

		Future NSPS Scenario, 2015			
	2011	Baseline	Option 1	Option 2 (Proposed)	Option 3
Energy-related CO_2-equivalent GHG Emissions (million metric tons CO_2-equivalent)					
Petroleum	2,359.59	2,433.60	2,433.12	2,433.49	2,433.45
Natural Gas	1,283.78	1,352.20	1,354.47	1,353.19	1,352.87
Coal	1,946.02	1,882.08	1,879.84	1,883.24	1,883.30
Other	11.99	11.99	11.99	11.99	11.99
Total	**5,601.39**	**5,679.87**	**5,679.42**	**5,681.91**	**5,681.61**
% Change in Energy-related CO_2-equivalent GHG Emissions from Baseline					
Petroleum			-0.02%	0.00%	-0.01%
Natural Gas			0.17%	0.07%	0.05%
Coal			-0.12%	0.06%	0.06%
Other			0.00%	0.00%	0.00%
Total			**-0.01%**	**0.04%**	**0.03%**

Note: Excludes "producer-side" emissions and emissions reductions estimated to result from NSPS alternatives. Totals may not sum due to independent rounding.

As is shown in Table 7-12, NSPS Option 1 is predicted to slightly decrease aggregate consumer-side energy-related CO_2-equivalent GHG emissions, by about 0.01 percent, while the mix of emissions shifts slightly away from coal and petroleum toward natural gas. Proposed Options 2 and 3 are estimated to increase consumer-side aggregate energy-related CO_2-equivalent GHG emissions by about 0.04 and 0.03 percent, respectively, mainly because consumer-side emissions from natural gas and coal combustion increase slightly.

7.3 Employment Impact Analysis

While a standalone analysis of employment impacts is not included in a standard cost-benefit analysis, such an analysis is of particular concern in the current economic climate of sustained high unemployment. Executive Order 13563, states, "Our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation" (emphasis added). Therefore, we seek to inform the discussion of labor demand and job impacts by providing an estimate of the employment impacts of the proposed regulations using labor requirements for the installation, operation, and

maintenance of control requirements, as well as reporting and recordkeeping requirements. Unlike several recent RIAs, however, we do not provide employment impacts estimates based on the study by Morgenstern et al. (2002); we discuss this decision after presenting estimates of the labor requirements associated with reporting and recordkeeping and the installation, operation, and maintenance of control requirements.

7.3.1 Employment Impacts from Pollution Control Requirements

Regulations set in motion new orders for pollution control equipment and services. New categories of employment have been created in the process of implementing regulations to make our air safer to breathe. When a new regulation is promulgated, a response of industry is to order pollution control equipment and services in order to comply with the regulation when it becomes effective. Revenue and employment in the environmental technology industry have grown steadily between 2000 and 2008, reaching an industry total of approximately $300 billion in revenues and 1.7 million employees in 2008.[52] While these revenues and employment figures represent gains for the environmental technologies industry, they are costs to the regulated industries required to install the equipment. Moreover, it is not clear the 1.7 million employees in 2008 represent new employment as opposed to workers being shifted from the production of goods and services to environmental compliance activities.

Once the equipment is installed, regulated firms hire workers to operate and maintain the pollution control equipment – much like they hire workers to produce more output. Morgenstern et al. (2002) examined how regulated industries respond to regulation. The authors found that, on average for the industries they studied, employment increases in regulated firms. Of course, these firms may also reassign existing employees to perform these activities.

[52] In 2008, the industry totaled approximately $315 billion in revenues and 1.9 million employees including indirect employment effects, pollution abatement equipment production employed approximately 4.2 million workers in 2008. These indirect employment effects are based on a multiplier for indirect employment = 2.24 (1982 value from Nestor and Pasurka - approximate middle of range of multipliers 1977-1991). Environmental Business International (EBI), Inc., San Diego, CA. Environmental Business Journal, monthly (copyright). http://www.ebiusa.com/ EBI data taken from the Department of Commerce International Trade Administration Environmental Industries Fact Sheet from April 2010: http://web.ita.doc.gov/ete/eteinfo.nsf/068f3801d047f26e85256883006ffa54/4878b7e2fc08ac6d85256883006c452c?OpenDocument

Environmental regulations support employment in many basic industries. In addition to the increase in employment in the environmental protection industry (via increased orders for pollution control equipment), environmental regulations also support employment in industries that provide intermediate goods to the environmental protection industry. The equipment manufacturers, in turn, order steel, tanks, vessels, blowers, pumps, and chemicals to manufacture and install the equipment. Bezdek et al. (2008) found that investments in environmental protection industries create jobs and displace jobs, but the net effect on employment is positive.

The focus of this part of the analysis is on labor requirements related to the compliance actions of the affected entities within the affected sector. We do not estimate any potential changes in labor outside of the oil and natural gas sector. This analysis estimates the employment impacts due to the installation, operation, and maintenance of control equipment, as well as employment associated with new reporting and recordkeeping requirements.

It is important to highlight that unlike the typical case where to reduce a bad output (i.e., emissions) a firm often has to reduce production of the good output, many of the emission controls required by the proposed NSPS will simultaneously increase production of the good output and reduce production of bad outputs. That is, these controls jointly produce environmental improvements and increase output in the regulated sector. New labor associated with implementing these controls to comply with the new regulations can also be viewed as additional labor increasing output while reducing undesirable emissions.

No estimates of the labor used to manufacture or assemble pollution control equipment or to supply the materials for manufacture or assembly are included because U.S. EPA does not currently have this information. The employment analysis uses a bottom-up engineering-based methodology to estimate employment impacts. The engineering cost analysis summarized in this RIA includes estimates of the labor requirements associated with implementing the proposed regulations. Each of these labor changes may either be required as part of an initial effort to comply with the new regulation or required as a continuous or annual effort to maintain compliance. We estimate up-front and continual, annual labor requirements by estimating hours of labor required and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). We note that this type of FTE estimate

cannot be used to make assumptions about the specific number of people involved or whether new jobs are created for new employees.

In other employment analyses U.S. EPA distinguished between employment changes within the regulated industry and those changes outside the regulated industry (e.g. a contractor from outside the regulated facility is employed to install a control device). For this regulation however, the structure of the industry makes this difficult. The mix of in-house versus contracting services used by firms is very case-specific in the oil and natural gas industry. For example, sometimes the owner of the well, processing plant, or transmission pipelines uses in–house employees extensively in daily operations, while in other cases the owner relies on outside contractors for many of these services. For this reason, we make no distinction in the quantitative estimates between labor changes within and outside of the regulated sector.

The results of this employment estimate are presented in Table 7-13 for the proposed NSPS and in Table 7-14 for the proposed NESHAP amendments. The tables breaks down the installation, operation, and maintenance estimates by type of pollution control evaluated in the RIA and present both the estimated hours required and the conversion of this estimate to FTE. For both the proposed NSPS and NESHAP amendments, reporting and recordkeeping requirements were estimated for the entire rules rather than by anticipated control requirements; the reporting and recordkeeping estimates are consistent with estimates EPA submitted as part of its Information Collection Request (ICR).

The up-front labor requirement is estimated at 230 FTEs for the proposed NSPS and about 120 FTEs for the proposed NESHAP amendments. These up-front FTE labor requirements can be viewed as short-term labor requirements required for affected entities to comply with the new regulation. Ongoing requirements are estimated at about 2,400 FTEs for the proposed NSPS and about 102 FTEs for the proposed NESHAP amendments. These ongoing FTE labor requirements can be viewed as sustained labor requirements required for affected entities to continuously comply with the new regulation

Two main categories contain the majority of the labor requirements for the proposed rules: implementing reduced emissions completions (RECs) and reporting and recordkeeping

requirements for the proposed NSPS. Also, note that pneumatic controllers have no up-front or continuing labor requirements. While the controls do require labor for installation, operation, and maintenance, the required labor is less than that of the controllers that would be used absent the regulation. In this instance, we assume the incremental labor requirements are zero.

Implementing RECs are estimated to require about 2,230 FTE, over 90 percent of the total continuing labor requirements for the proposed NSPS.[53] We denote REC-related requirements as continuing, or annual, as the REC requirements will in fact recur annually, albeit at different wells each year. The REC requirements are associated with certain new well completions or existing well recompletions, which while individual completions occur over a short period of time (days to a few weeks), new wells and other existing wells are completed or recompleted annually. Because of these reasons, we assume the REC-related labor requirements are annual.

7.3.2 Employment Impacts Primarily on the Regulated Industry

In previous RIAs, we transferred parameters from a study by Morgenstern et al. (2002) to estimate employment effects of new regulations. (See, for example, the Regulatory Impact Analysis for the recently finalized Industrial Boilers and CISWI rulemakings, promulgated on February 21, 2011). The fundamental insight of Morgenstern, et al. is that environmental regulations can be understood as requiring regulated firms to add a new output (environmental quality) to their product mixes. Although legally compelled to satisfy this new demand, regulated firms have to finance this additional production with the proceeds of sales of their other (market) products. Satisfying this new demand requires additional inputs, including labor, and may alter the relative proportions of labor and capital used by regulated firms in their production processes.

Morgenstern et al. concluded that increased abatement expenditures in these industries generally do not cause a significant change in employment. Using plant-level Census

[53] As shown on earlier in this section, we project that the number of successful natural gas wells drilled in 2015 will decline slightly from the baseline projection. Therefore, there may be small employment losses in drilling-related employment that partly offset gains in employment from compliance-related activities.

information between the years 1979 and 1991, Morgenstern et al. estimate the size of each effect for four polluting and regulated industries (petroleum refining, plastic material, pulp and paper, and steel). On average across the four industries, each additional $1 million (1987$) spending on pollution abatement results in a (statistically insignificant) net increase of 1.55 (+/- 2.24) jobs. As a result, the authors conclude that increases in pollution abatement expenditures do not necessarily cause economically significant employment changes.

For this version of RIA for the proposed NSPS and NESHAP amendments, however, we chose not to quantitatively estimate employment impacts using Morgenstern et al. because of reasons specific to the oil and natural gas industry and proposed rules. We believe the transfer of parameter estimates from the Morgenstern et al. study to the proposed NSPS and NESHAP amendments is beyond the range of the study for two reasons.

Table 7-13 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Proposed NSPS Option in 2015

Source/Emissions Point	Emissions Control	Projected No. of Affected Units	Per Unit Up- Front Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total Up- Front Labor Estimate (hours)	Total Annual Labor Estimate (hours)	Up-Front Full-Time Equivalent	Annual Full-Time Equivalent
Well Completions								
Hydraulically Fractured Gas Wells	Reduced Emissions Completion (REC)	9,313	0	218	0	2,025,869	0.0	974.0
Hydraulically Fractured Gas Wells	Combustion	446	0	22	0	9,626	0.0	4.6
Well Recompletions								
Hydraulically Fractured Gas Wells (pre-NSPS wells)	REC	12,050	0	218	0	2,621,126	0.0	1,260.2
Equipment Leaks								
Processing Plants	NSPS Subpart VVA	29	587	887	17,023	25,723	8.2	12.4
Reciprocating Compressors								
Gathering/Boosting Stations	AMM	210	1	1	210	210	0.1	0.1
Processing Plants	AMM	375	1	1	375	375	0.2	0.2
Transmission Compressor Stations	AMM	199	1	1	199	199	0.1	0.1
Underground Storage Facilities	AMM	9	1	1	9	9	0.0	0.0
Centrifugal Compressors								
Processing Plants	Dry Seals/Route to Process or Control	16	355	0	5,680	0	2.7	0.0
Transmission Compressor Stations	Dry Seals/Route to Process or Control	14	355	0	4,970	0	2.4	0.0
Pneumatic Controllers								
Oil and Gas Production	Low Bleed/Route to Process	13,632	0	0	0	0	0.0	0.0
Natural Gas Trans. and Storage	Low Bleed/Route to Process	67	0	0	0	0	0.0	0.0
Storage Vessels								
High Throughput	95% control	304	271	190	82,279	57,582	39.6	27.7
Reporting and Recordkeeping for Complete NSPS		---	---	---	360,443	201,342	173.3	96.8
TOTAL		**---**	**---**	**---**	**471,187**	**4,942,060**	**226.5**	**2,376.0**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

Table 7-14 Labor-based Employment Estimates for Reporting and Recordkeeping and Installing, Operating, and Maintaining Control Equipment Requirements, Proposed NESHAP Amendments in 2015

Source/Emissions Point	Emissions Control	Projected No. of Affected Units	Per Unit One-time Labor Estimate (hours)	Per Unit Annual Labor Estimate (hours)	Total One-Time Labor Estimate (hours)	Total Annual Labor Estimate (hours)	One-time Full-Time Equivalent	Annual Full-Time Equivalent
Small Glycol Dehydrators								
Production	Combustion devices, recovery devices, process modifications	115	27	285	3,108	32,821	1.5	15.8
Transmission	Combustion devices, recovery devices, process modifications	19	27	285	513	5,423	0.2	2.6
Storage Vessels								
Production	Combustion devices, recovery devices	674	311	198	209,753	133,231	100.8	64.1
Reporting and Recordkeeping for Complete NESHAP Amendments		---	---	---	36,462	39,923	17.5	19.2
TOTAL		**---**	**--**	**---**	**249,836**	**211,398**	**120.1**	**101.6**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by the per unit labor requirements and then multiplying by 2,080 (40 hours multiplied by 52 weeks). Totals may not sum due to independent rounding.

First, the possibility that the revenues producers are estimated to receive from additional natural gas recovery as a result of the proposed NSPS might offset the costs of complying with the rule presents challenges to estimating employment effects (see Section 3.2.2.1 of the RIA for a detailed discussion of the natural gas recovery). The Morgenstern et al. paper, for example, is intended to analyze the impact of environmental compliance expenditures on industry employment levels, and it may not be appropriate to draw on their demand and net effects when compliance costs are expected to be negative.

Second, the proposed regulations primarily affect the natural gas production, processing, and transmission segments of the industry. While the natural gas processing segment of the oil and natural gas industry is similar to petroleum refining, which is examined in Morgenstern et al., the production side of the oil and natural gas (drilling and extraction, primarily) and natural gas pipeline transmission are not similar to petroleum refining. Because of the likelihood of negative compliance costs for the proposed NSPS and the segments of the oil and natural gas industry affected by the proposals are not examined by Morgenstern et al., we decided not to use the parameters estimated by Morgenstern et al. to estimate within-industry employment effects for the proposed oil and natural gas NESHAP amendments and NSPS.

That said, the likelihood of additional natural gas recovery is an important component of the market response to the rule, as it is expected that this additional natural gas recovery will reduce the price of natural gas. Because of the estimated fall in prices in the natural gas sector due to the proposed NSPS, prices in other sectors that consume natural gas are likely drop slightly due to the decrease in energy prices. This small production increase and price decrease may have a slight stimulative effect on employment in industries that consume natural gas.

7.4 Small Business Impacts Analysis

The Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a

significant economic impact on a substantial number of small entities. Small entities include small businesses, small governmental jurisdictions, and small not-for-profit enterprises.

After considering the economic impact of the proposed rules on small entities for both the NESHAP and NSPS, the screening analysis indicates that these proposed rules will not have a significant economic impact on a substantial number of small entities (or "SISNOSE"). The supporting analyses for these determinations are presented in this section of the RIA.

As discussed in previous sections of the economic impact analysis, under the proposed NSPS, some affected producers are likely to be able to recover natural gas that would otherwise be vented to the atmosphere, as well as recover saleable condensates that would otherwise be emitted. EPA estimates that the revenues from this additional natural gas product recovery will offset the costs of implementing control options implemented as a result of the Proposed NSPS. Because the total costs of the rule are likely to be more than offset by the revenues producers gain from increased natural gas recovery, we expect there will be no SISNOSE arising from the proposed NSPS. However, not all components of the proposed NSPS are estimated to have cost savings. Therefore, we analyze potential impacts to better understand the potential distribution of impacts across industry segments and firms. We feel taking this approach strengthens the determination that there will be no SISNOSE. Unlike the controls for the proposed NSPS, the controls evaluated under the proposed NESHAP amendments do not recover significant quantities of natural gas products.

7.4.1 Small Business National Overview

The industry sectors covered by the final rule were identified during the development of the engineering cost analysis. The U.S. Census Bureau's Statistics of U.S. Businesses (SUSB) provides national information on the distribution of economic variables by industry and enterprise size. The Census Bureau and the Office of Advocacy of the Small Business Administration (SBA) supported and developed these files for use in a broad range of economic analyses.[54] Statistics include the total number of establishments, and receipts for all entities in an industry; however, many of these entities may not necessarily be covered by the final rule. SUSB also provides statistics by enterprise employment and receipt size (Table 7-15 and Table 7-16).

[54]See http://www.census.gov/csd/susb/ and http://www.sba.gov/advocacy/ for additional details.

The Census Bureau's definitions used in the SUSB are as follows:

- *Establishmen*t: A single physical location where business is conducted or where services or industrial operations are performed.
- *Firm:* A firm is a business organization consisting of one or more domestic establishments in the same state and industry that were specified under common ownership or control. The firm and the establishment are the same for single-establishment firms. For each multi-establishment firm, establishments in the same industry within a state will be counted as one firm- the firm employment and annual payroll are summed from the associated establishments.
- *Receipts*: Receipts (net of taxes) are defined as the revenue for goods produced, distributed, or services provided, including revenue earned from premiums, commissions and fees, rents, interest, dividends, and royalties. Receipts exclude all revenue collected for local, state, and federal taxes.
- *Enterprise*: An enterprise is a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the sum of employment of all associated establishments.

Because the SBA's business size definitions (SBA, 2008) apply to an establishment's "ultimate parent company," we assumed in this analysis that the "firm" definition above is consistent with the concept of ultimate parent company that is typically used for SBREFA screening analyses, and the terms are used interchangeably.

Table 7-15 Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007

NAICS	NAICS Description	SBA Size Standard (effective Nov. 5, 2010)	Owned by Firms with: < 20 Employees	20-99 Employees	100-499 Employees	Total < 500 Employees	> 500 Employees	Total Firms
Number of Firms by Firm Size								
211111	Crude Petroleum and Natural Gas Extraction	500	5,759	455	115	6,329	95	6,424
211112	Natural Gas Liquid Extraction	500	77	9	12	98	41	139
213111	Drilling Oil and Gas Wells	500	1,580	333	97	2,010	49	2,059
486210	Pipeline Transportation of Natural Gas	$7.0 million	63	12	9	84	42	126
Total Employment by Firm Size								
211111	Crude Petroleum and Natural Gas Extraction	500	21,170	16,583	17,869	55,622	77,664	133,286
211112	Natural Gas Liquid Extraction	500	372	305	1,198	1,875	6,648	8,523
213111	Drilling Oil and Gas Wells	500	5,972	13,787	16,893	36,652	69,774	106,426
486210	Pipeline Transportation of Natural Gas	$7.0 million	241	382	1,479	2,102	22,581	24,683
Estimated Receipts by Firm Size ($1000)								
211111	Crude Petroleum and Natural Gas Extraction	500	12,488,688	15,025,443	17,451,805	44,965,936	149,141,316	194,107,252
211112	Natural Gas Liquid Extraction	500	209,640	217,982	1,736,706	2,164,328	37,813,413	39,977,741
213111	Drilling Oil and Gas Wells	500	1,101,481	2,460,301	3,735,652	7,297,434	16,550,804	23,848,238
486210	Pipeline Transportation of Natural Gas	$7.0 million	332,177	518,341	1,448,020	2,298,538	18,498,143	20,796,681

Source: U.S. Census Bureau. 2010. "Number of Firms, Number of Establishments, Employment, Annual Payroll, and Estimated Receipts by Enterprise Receipt Size for the United States, All Industries: 2007." <http://www.census.gov/econ/susb/>

Table 7-16 Distribution of Small and Large Firms by Number of Firms, Total Employment, and Estimated Receipts by Firm Size and NAICS, 2007

NAICS	NAICS Description	Total Firms	Percent of Firms: Small Businesses	Percent of Firms: Large Businesses	Percent of Firms: Total Firms
Number of Firms by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	6,424	98.5%	1.5%	100.0%
211112	Natural Gas Liquid Extraction	139	70.5%	29.5%	100.0%
213111	Drilling Oil and Gas Wells	2,059	97.6%	2.4%	100.0%
486210	Pipeline Transportation of Natural Gas	126	48.4%	51.6%	100.0%
Total Employment by Firm Size					
211111	Crude Petroleum and Natural Gas Extraction	133,286	41.7%	58.3%	100.0%
211112	Natural Gas Liquid Extraction	8,523	22.0%	78.0%	100.0%
213111	Drilling Oil and Gas Wells	106,426	34.4%	65.6%	100.0%
486210	Pipeline Transportation of Natural Gas	24,683	N/A*	N/A*	N/A*
Estimated Receipts by Firm Size ($1000)					
211111	Crude Petroleum and Natural Gas Extraction	194,107,252	23.2%	76.8%	100.0%
211112	Natural Gas Liquid Extraction	39,977,741	5.4%	94.6%	100.0%
213111	Drilling Oil and Gas Wells	23,848,238	30.6%	69.4%	100.0%
486210	Pipeline Transportation of Natural Gas	20,796,681	N/A*	N/A*	N/A*

Note: Employment and receipts could not be broken down between small and large businesses because of non-disclosure requirements.

Source: SBA

While the SBA and Census Bureau statistics provide informative broad contextual information on the distribution of enterprises by receipts and number of employees, it is also useful to additionally contrast small and large enterprises (where large enterprises are defined as those that are not small, according to SBA criteria) in the oil and natural gas industry. The summary statistics presented in previous tables indicate that there are a large number of relatively small firms and a small number of large firms. Given the majority of expected impacts of the proposed rules arises from well completion-related requirements, which impacts production activities, exclusively, some explanation of this particular market structure is warranted as it pertains to production and small entities. An important question to answer is whether there are particular roles that small entities serve in the production segment of the oil and natural gas industry that may be disproportionately affected by the proposed rules.

The first important broad distinction among firms is whether they are independent or integrated. Independent firms concentrate on exploration and production (E&P) activities, while integrated firms are vertically integrated and often have operations in E&P, processing, refining, transportation, and retail. To our awareness, there are no small integrated firms. Independent firms may own and operate wells or provide E&P-related services to the oil and gas industry. Since we are focused on evaluating potential impacts to small firms owning and operating new and existing hydraulically fractured wells, we should narrow down on this sector.

In our understanding, there is no single industry niche for small entities in the production segment of the industry since small operators have different business strategies and that small entities can own different types of wells. The organization of firms in oil and natural gas industry also varies greatly from firm to firm. Additionally, oil and natural gas resources vary widely geographically and can vary significantly within a single field.

Among many important roles, independent small operators historically pioneered exploration in new areas, as well as developed new technologies. By taking on these relatively large risks, these small entrepreneurs (wildcatters) have been critical sources of industrial innovation and opened up critical new energy supplies for the U.S. (HIS Global Insight). In recent decades, as the oil and gas industry has concentrated via mergers, many of these smaller firms have been absorbed into large firms.

Another critical role, which provides an interesting contrast to small firms pioneering new territory, is that smaller independents maintain and operate a large proportion of the Nation's low producing wells, which are also known as marginal or stripper wells (Duda et al. 2005). While marginal wells represent about 80 percent of the population of producing wells, they produce about 15 percent of domestic production, according to EIA (Table 7-17).

Table 7-17 Distribution of Crude Oil and Natural Gas Wells by Productivity Level, 2009

Type of Wells	Wells (no.)	Wells (%)	Production (MMbbl for oil and Bcf gas)	Production (%)
Crude Oil				
Stripper Wells (<15 boe per year)	310,552	85%	311	19%
Other Wells (>=15 boe per year)	52,907	15%	1,331	81%
Total Crude Oil Wells	**363,459**	**100%**	**1,642**	**100%**
Natural Gas				
Natural Gas Stripper Wells (<15 boe per year)	338,056	73%	2,912	12%
Other Natural Gas Wells (>=15 boe per year)	123,332	27%	21,048	88%
Total Natural Gas Wells	**461,388**	**100%**	**23,959**	**100%**

Source: U.S. Energy Information Administration, **Distribution of Wells by Production Rate Bracket.** <http://www.eia.gov/pub/oil_gas/petrosystem/us_table.html> Accessed 7/10/11.

Note: Natural gas production converted to barrels oil equivalent (boe) uses the conversion of 0.178 barrels of crude oil to 1000 cubic feet natural gas.

Many of these wells were likely drilled and initially operated by major firms (although the data are not available to quantify the percentage of wells initially drilled by small versus large producers). Well productivity levels typically follow a steep decline curve; high production in earlier years but sustained low production for decades. Because of relatively low overhead of maintaining and operating few relatively co-located wells, some small operators with a particular business strategy purchase low producing wells from the majors, who concentrate on new opportunities. As small operators have provided important technical innovation in exploration, small operators have also been sources of innovation in extending the productivity and lifespan of existing wells (Duda et al. 2005).

7.4.2 Small Entity Economic Impact Measures

The proposed Oil and Natural Gas NSPS and NESHAP amendments will affect the owners of the facilities that will incur compliance costs to control their regulated emissions. The owners, either firms or individuals, are the entities that will bear the financial impacts associated with these additional operating costs. The proposed rule has the potential to impact all firms owning affected facilities, both large and small.

The analysis provides EPA with an estimate of the magnitude of impacts the proposed NSPS and NESHAP amendments may have on the ultimate domestic parent companies that own facilities EPA expects might be impacted by the rules. The analysis focuses on small firms because they may have more difficulty complying with a new regulation or affording the costs associated with meeting the new standard. This section presents the data sources used in the screening analysis, the methodology we applied to develop estimates of impacts, the results of the analysis, and conclusions drawn from the results.

The small business impacts analysis for the NSPS and NESHAP amendments relies upon a series of firm-level sales tests (represented as cost-to-revenue ratios) for firms that are likely to be associated with NAICS codes listed in Table 7-15. For both the NSPS and NESHAP amendments, we obtained firm-level employment, revenues, and production levels using various sources, including the American Business Directory, the *Oil and Gas Journal*, corporate websites, and publically-available financial reports. Using these data, we estimated firm-level compliance cost impacts and calculated cost-to-revenue ratios to identify small firms that might be significantly impacts by the rules. The approaches taken for the NSPS and NESHAP amendments differed; more detail on approaches for each set of proposed rules is presented in the following sections.

For the sales test, we divided the estimates of annualized establishment compliance costs by estimates of firm revenue. This is known as the cost-to-revenue ratio, or the "sales test." The "sales test" is the impact methodology EPA employs in analyzing small entity impacts as opposed to a "profits test," in which annualized compliance costs are calculated as a share of profits. The sales test is often used because revenues or sales data are commonly available for entities impacted by EPA regulations, and profits data normally made available are often not the true profit earned by firms because of accounting and tax considerations. Revenues as typically published are correct figures and are more reliably reported when compared to profit data. The use of a "sales test" for estimating small business impacts for a rulemaking such as this one is consistent with guidance offered by EPA on compliance with SBREFA[55] and is consistent with guidance published by the U.S. SBA's Office of Advocacy that suggests that cost as a percentage

[55] The SBREFA compliance guidance to EPA rulewriters regarding the types of small business analysis that should be considered can be found at <http://www.epa.gov/sbrefa/documents/rfaguidance11-00-06.pdf>

of total revenues is a metric for evaluating cost increases on small entities in relation to increases on large entities (U.S. SBA, 2010).[568]

7.4.3 Small Entity Economic Impact Analysis, Proposed NSPS

7.4.3.1 Overview of Sample Data and Methods

The proposed NSPS covers emissions points within various stages of the oil and natural gas production process. We expect that firms within multiple NAICS codes will be affected, namely the NAICS categories presented in Table 7-15. Because of the diversity of the firms potentially affected, we decided to analyze three distinct groups of firms within the oil and natural gas industry, while accounting for overlap across the groups. We analyze firms that are involved in oil and natural gas extraction that are likely to drill and operate wells, while a subset are integrated firms involved in multiple segments of production, as well as retailing products. We also analyze firms that primarily operate natural gas processing plants. A third set of firms we analyzed contains firms that primarily operate natural gas compression and pipeline transmission.

To identify firms involved in the drilling and primary production of oil and natural gas, we relied upon the annual *Oil and Gas Journal* 150 Survey (OGJ 150) as described in the Industry Profile in Section 2. While the OGJ 150 lists public firms, we believe the list is reasonably representative of the larger population of public and private firms operating in this segment of the industry. While the proportion of small firm in the OGJ 150 is smaller than the proportion evaluated by the Census SUSB, the OGJ 150 provides detailed information on the production activities and financial returns of the firms within the list, which are critical ingredients to the small business impacts analysis. We drew upon the OGJ 150 lists published for the years 2008 and 2009 (*Oil and Gas Journal*, September 21, 2009 and *Oil and Gas Journal*, September 6, 2010). The year 2009 saw relatively low levels of drilling activities because of the economic recession, while 2008 saw a relatively high level of drilling activity because of high fuel prices. Combined, we believe these two years of data are representative.

[56]U.S. SBA, Office of Advocacy. A Guide for Government Agencies, How to Comply with the Regulatory Flexibility Act, Implementing the President's Small Business Agenda and Executive Order 13272, June 2010.

To identify firms that process natural gas, the OGJ also releases a period report entitled "Worldwide Gas Processing Survey", which provides a wide range of information on existing processing facilities. We used the most recent list of U.S. gas processing facilities[57] and other resources, such as the American Business Directory and company websites, to best identify the parent company of the facilities. To identify firms that compress and transport natural gas via pipelines, we examined the periodic OGJ survey on the economics of the U.S. pipeline industry. This report examines the economic status of all major and non-major natural gas pipeline companies.[58] For these firms, we also used the American Business Directory and corporate websites to best identify the ultimate owner of the facilities or companies.

After combining the information for exploration and production firms, natural gas processing firms, and natural gas pipeline transmission firms in order to identify overlaps across the list, the approach yielded a sample of 274 firms that would potentially be affected by the proposed NSPS in 2015 assuming their 2015 production activities were similar to those in 2008 and 2009. We estimate that 129 (47 percent) of these firms are small according to SBA criteria. We estimate 121 firms (44 percent) are not small firms according to SBA criteria. We are unable to classify the remaining 24 firms (9 percent) because of a lack of required information on employee counts or revenue estimates.

Table 7-18 shows the estimated revenues for 250 firms for which we have sufficient data that would be potentially affected by the proposed NSPS based upon their activities in 2008 and 2009. We segmented the sample into four groups, production and integrated firms, processing firms, pipeline firms, and pipelines/processing firms. For the firms in the pipelines/processing group, we were unable to determine the firms' primary line of business, so we opted to group together as a fourth group.

[57] Oil and Gas Journal. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010.
[58] Oil and Gas Journal. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

Table 7-18 Estimated Revenues for Firms in Sample, by Firm Type and Size

		Estimated Revenues (millions, 2008 dollars)				
Firm Type/Size	Number of Firms	Total	Average	Median	Minimum	Maximum
Production and Integrated						
Small	79	18,554.5	234.9	76.3	0.1	1,116.9
Large	49	1,347,463.0	27,499.2	1,788.3	12.9	310,586.0
Subtotal	128	1,366,017.4	10,672.0	344.6	0.1	310,586.0
Pipeline						
Small	11	694.5	63.1	4.6	0.5	367.0
Large	36	166,290.2	4,619.2	212.9	7.1	112,493.0
Subtotal	47	166,984.6	3,552.9	108.0	0.5	112,493.0
Processing						
Small	39	4,972.1	127.5	26.9	1.9	1,459.1
Large	23	177,632.1	8,881.6	2,349.4	10.4	90,000.0
Subtotal	62	182,604.2	3,095.0	41.3	1.9	90,000.0
Pipelines/Processing						
Small	0	N/A	N/A	N/A	N/A	N/A
Large	13	175,128.5	13,471.4	6,649.4	858.6	71,852.0
Subtotal	13	175,128.5	13,471.4	6,649.4	858.6	71,852.0
Total						
Small	**129**	**24,221.1**	**187.8**	**34.9**	**0.1**	**1,459.1**
Large	**121**	**1,866,513.7**	**15,817.9**	**1,672.1**	**7.1**	**310,586.0**
Total	**250**	**1,890,734.8**	**7,654.8**	**163.9**	**0.1**	**310,586.0**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. *Oil and Gas Journal*. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010, with additional analysis to determine ultimate ownership of plants. *Oil and Gas Journal*. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010. American Business Directory was used to determine number of employees.

As shown in Table 7-18, there is a wide variety of revenue levels across firm size, as well as across industry segments. The estimated revenues within the sample are concentrated on integrated firms and firms engaged in production activities (the E&P firms mentioned earlier).

The oil and natural gas industry is capital-intensive. To provide more context on the potential impacts of new regulatory requirements, Table 7-19 presents descriptive statistics for small and large integrated and production firms from the sample of firms (121 of the 128 integrated and production firms listed in the *Oil and Gas Journal*; capital and exploration expenditures for 7 firms were not reported in the *Oil and Gas Journal*).

Table 7-19 Descriptive Statistics of Capital and Exploration Expenditures, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars)

		Capital and Exploration Expenditures (millions, 2008 dollars)				
Firm Size	Number	Total	Average	Median	Minimum	Maximum
Small	76	13,478.8	177.4	67.1	0.1	2,401.9
Large	45	126,749.3	2,816.7	918.1	10.3	22,518.7
Total	**121**	**140,228.2**	**1,158.9**	**192.8**	**0.1**	**22,518.7**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. American Business Directory was used to determine number of employees.

The average 2008 and 2009 total capital and exploration expenditures for the sample of 121 firms were $140 billion in 2008 dollars). About 10 percent of this total was spent by small firms. Average capital and explorations expenditures for small firms are about 6 percent of large firms; median expenditures of small firms are about 7 percent of large firms' expenditures. For small firms, capital and exploration expenditures are high relative to revenue, which appears to hold true more generally for independent E&P firms compared to integrated major firms. This would seem to indicate the capital-intensive nature of E&P activities. As expected, this would drive up ratios comparing estimated engineering costs to revenues and capital and exploration expenditures.

Table 7-20 breaks down the estimated number of natural gas and crude oil wells drilled by the 121 firms in the sample for which the *Oil and Gas Journal* information reported well-drilling estimates. Note the fractions on the minimum and maximum statistics; the fractions reported are due to our assumptions to estimate oil and natural gas wells drilled from the total wells drilled reported by the *Oil and Gas Journal*. The OGJ150 lists new wells drilled by firm in 2008 and 2009, but the drilling counts are not specific to crude oil or natural gas wells. We

apportion the wells drilled to natural gas and crude oil wells using the distribution of well drilling in 2009 (63 percent natural gas and 37 percent oil).

Table 7-20 Descriptive Statistics of Estimated Wells Drilled, Small and Large Firms in Sample, 2008 and 2009 (million 2008 dollars)

			Estimated Average Wells Natural Gas and Crude Oil Wells Drilled (2008 and 2009)				
Well Type	Firm Size	Number of Firms	Total	Average	Median	Minimum	Maximum
Natural Gas							
	Small	76	2,288.3	30.1	6.0	0.2	259.3
	Large	45	9,445.1	209.9	149.1	0.6	868.3
	Subtotal	121	11,733.4	97.0	28.3	0.2	868.3
Crude Oil							
	Small	76	1,317.1	17.3	3.5	0.1	149.2
	Large	45	5,436.3	120.8	85.8	0.4	499.7
	Subtotal	121	6,753.4	55.8	16.3	0.1	499.7
Total							
	Small	**76**	**3,605.4**	**47.4**	**9.5**	**0.0**	**408.5**
	Large	**45**	**14,881.4**	**330.7**	**234.9**	**0.0**	**1,368.0**
	Total	**121**	**18,486.8**	**152.8**	**44.6**	**0.0**	**1,368.0**

Sources: *Oil and Gas Journal*. "OGJ150." September 21, 2009; *Oil and Gas Journal*. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010. American Business Directory was used to determine number of employees.

This table highlights the fact that many firms drill relatively few wells; the median for small firms is 6 natural gas wells compared to 149 for large firms. Later in this section, we examine whether this distribution has implications for the engineering costs estimates, as well as the estimates of expected natural product recovery from controls such as RECs.

Unlike the analysis that follows for the analysis of impacts on small business from the NESHAP amendments, we have no specific data on potentially affected facilities under the NSPS. The NSPS will apply to new and modified sources, for which data are not fully available in advance, particularly in the case of new and modified sources such as well completions and recompletions which are spatially diffuse and potentially large in number.

The engineering cost analysis estimated compliance costs in a top-down fashion, projecting the number of new sources at an annual level and multiplying these estimates by

model unit-level costs to estimate national impacts. To estimate per-firm compliance costs in this analysis, we followed a procedure similar to that of entering estimate compliance costs in NEMS on a per well basis. We first use the OGJ150-based list to estimate engineering compliance costs for integrated and production companies that may operate facilities in more than one segment of the oil and natural gas industry. We then estimate the compliance costs per crude oil and natural gas well by totaling all compliance costs estimates in the engineering cost estimates for the proposed NSPS and dividing that cost by the total number of crude oil and natural gas wells forecast as of 2015, the year of analysis. These compliance costs include the expected revenue from natural gas and condensate recovery that result from implementation of some proposed controls.

This estimation procedure yielded an estimate of crude well compliance costs of $162 per drilled well and natural gas well compliance costs of $38,719 without considering estimated revenues from product recovery and -$2,455 per drilled well with estimated revenues from product recovery included. Note that the divergence of estimated per well costs between crude oil and natural gas wells is because the proposed NSPS requirements are primary directed toward natural gas wells. Also note that the per well cost savings estimate for natural gas wells is different than the estimated cost of implementing a REC; this difference is because this estimate is picking up savings from other control options. We then estimate a single-year, firm-level compliance cost for this subset of firms by multiplying the per well cost estimates with the well count estimates.

The OGJ reports plant processing capacity in terms of MMcf/day. In the energy system impacts analysis, the NEMS model estimates a 6.5 percent increase (from 21.05 tcf in 2011 to 22.43 tcf in 2015) in domestic natural gas production from 2011 to 2015, the analysis year. On this, basis, we estimate that natural gas processing capacity for all plants in the OGJ list will increase 1.3 percent per year. This annual increment is equivalent to an increase in national gas processing capacity of 350 bcf per year. We assume that the engineering compliance costs estimates associated with processing are distributed according to the proportion of the increased national processing capacity contributed by each processing plant. These costs are estimated at $6.9 million without estimated revenues from product recovery and $2.3 million with estimated

revenues from product recovery, respectively, in 2008 dollars, or about $20/MMcf without revenues and $7/MMcf with revenues.

The OGJ report on pipeline companies has the advantage that it reports expenditures on plant additions. We assume that the firm-level proposed compression and transmission-related NSPS compliance costs are proportional to the expenditures on plant additions and that these additions reflect a representative year or this analysis. We estimate the annual compression and transmission-related NSPS compliance costs at $5.5 million without estimated revenues from product recovery and $3.7 million with estimated revenues from product recovery, respectively, in 2008 dollars.

7.4.3.2 Small Entity Impact Analysis, Proposed NSPS, Results

Summing estimated annualized engineering compliance costs across industry segment and individual firms in our sample, we estimate firms in the OGJ-based sample will face about $480 million in 2008 dollars, about 65 percent of the estimated annualized costs of the Proposed NSPS without including revenues from additional product recovery ($740 million). When including revenues from additional product recovery, the estimated compliance costs for the firms in the sample is about -$23 million, compared to engineering cost estimate of -$45 million.

Table 7-21 presents the distribution of estimated proposed NSPS compliance costs across firm size for the firms within our sample. Evident from this table, about 98 percent of the estimated engineering compliance costs accrue to the integrated and production segment of the industry, again explain by the fact that completion-related requirements contribute the bulk of the estimated engineering compliance costs (as well as estimated emissions reductions). About 17 percent of the total estimated engineering compliance costs (and about 18 percent of the costs accruing the integrated and production segment) are focused on small firms.

Table 7-21 Distribution of Estimated Proposed NSPS Compliance Costs Without Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

		Estimated Engineering Compliance Costs Without Estimated Revenues from Natural Gas Product Recovery (2008 dollars)				
Firm Type/Size	Number of Firms	Total	Mean	Median	Minimum	Maximum
Production and Integrated						
Small	79	82,293,903	1,041,695	221,467	3,210	10,054,401
Large	49	387,489,928	7,907,958	5,730,634	15,238	33,677,388
Subtotal	128	469,783,831	3,670,186	969,519	3,210	33,677,388
Pipeline						
Small	11	3,386	308	111	18	1,144
Large	36	1,486,929	41,304	3,821	37	900,696
Subtotal	47	1,490,314	31,709	2,263	18	900,696
Processing						
Small	39	476,165	12,209	1,882	188	276,343
Large	23	859,507	37,370	8,132	38	423,645
Subtotal	62	1,335,672	21,543	2,730	38	423,645
Pipelines/Processing						
Small	0	N/A	N/A	N/A	N/A	N/A
Large	13	5,431,510	417,808	147,925	2,003	2,630,236
Subtotal	13	5,431,510	417,808	147,925	2,003	2,630,236
Total						
Small	**129**	**82,773,454**	**641,655**	**49,386**	**18**	**10,054,401**
Large	**121**	**395,267,874**	**3,266,677**	**57,220**	**37**	**33,677,388**
Total	**250**	**478,041,328**	**1,912,165**	**55,888**	**18**	**33,677,388**

These distributions are similar when the revenues from expected natural gas recovery are included (Table 7-22). About 21 percent of the total savings from the proposed NSPS is expected to accrue to small firms (about 19 percent of the savings to the integrated and production segment accrue to small firms). Note also in Table 7-22 that the pipeline and processing segments (and the pipeline/processing firms) are not expected to experience net cost savings (negative costs) from the proposed NSPS.

Table 7-22 Distribution of Estimated Proposed NSPS Compliance Costs With Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

		Estimated Engineering Compliance Costs With Estimated Revenues from Natural Gas Product Recovery (millions, 2008 dollars)				
Firm Type/Size	Number of Firms	Total	Mean	Median	Minimum	Maximum
Production and Integrated						
Small	79	-5,065,551	-64,121	-13,729	-620,880	8,699
Large	49	-22,197,126	-453,003	-318,551	-2,072,384	423,760
Subtotal	128	-27,262,676	-212,990	-43,479	-2,072,384	423,760
Pipeline						
Small	11	2,303	209	76	12	779
Large	36	1,011,572	28,099	2,599	25	612,753
Subtotal	47	1,013,876	21,572	1,539	12	612,753
Processing						
Small	39	160,248	4,109	634	63	93,000
Large	23	289,258	12,576	2,737	13	142,573
Subtotal	62	449,506	7,250	919	13	142,573
Pipelines/Processing						
Small	0	---	---	---	---	---
Large	13	3,060,373	235,413	86,301	716	1,746,730
Subtotal	13	3,060,373	235,413	86,301	716	1,746,730
Total						
Small	**129**	**-4,902,999**	**-38,008**	**-2,520**	**-620,880**	**93,000**
Large	**121**	**-17,835,922**	**-147,404**	**634**	**-2,072,384**	**1,746,730**
Total	**250**	**-22,738,922**	**-90,956**	**22**	**-2,072,384**	**1,746,730**

Table 7-23 Summary of Sales Test Ratios, Without Revenues from Additional Natural Gas Product Recovery for Firms Affected by Proposed NSPS

		Descriptive Statistics for Sales Test Ratio Without Estimated Revenues from Natural Gas Product Recovery (%)			
Firm Type/Size	Number of Firms	Mean	Median	Minimum	Maximum
Production and Integrated					
Small	79	2.18%	0.49%	0.01%	50.83%
Large	49	0.41%	0.28%	<0.01%	2.83%
Subtotal	128	1.50%	0.39%	<0.01%	50.83%
Pipeline					
Small	11	<0.01%	<0.01%	<0.01%	0.01%
Large	36	0.01%	<0.01%	<0.01%	0.06%
Subtotal	47	0.01%	<0.01%	<0.01%	0.06%
Processing					
Small	39	0.05%	0.01%	<0.01%	0.33%
Large	23	0.02%	0.01%	<0.01%	0.15%
Subtotal	62	0.04%	0.01%	<0.01%	0.33%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	<0.01%	<0.01%	<0.01%	0.01%
Subtotal	13	<0.01%	<0.01%	<0.01%	0.01%
Total					
Small	**129**	**1.34%**	**0.15%**	**<0.01%**	**50.83%**
Large	**121**	**0.17%**	**0.01%**	**<0.01%**	**2.83%**
Total	**250**	**0.78%**	**0.03%**	**<0.01%**	**50.83%**

The mean cost-sales ratio for all businesses when estimated product recovery is excluded from the analysis of the sample data is 0.78 percent, with a median ratio of 0.03 percent, a minimum of less than 0.01 percent, and a maximum of over 50 percent (Table 7-23). For small firms in the sample, the mean and median cost-sales ratios are 1.34 percent and 0.15 percent, respectively, with a minimum of less than 0.01 percent and a maximum of over 50 percent (Table 7-23). Each of these statistics indicates that, when considered in the aggregate, impacts are relatively higher on small firms than large firms when the estimated revenue from additional natural gas product recovery is excluded. However, as the next table shows, the reverse is true when these revenues are included.

Table 7-24 Summary of Sales Test Ratios, With Revenues from Additional Natural Gas Product Recovery for Firms Affected by Proposed NSPS

		Descriptive Statistics for Sales Test Ratio With Estimated Revenues from Natural Gas Product Recovery (%)			
Firm Type/Size	Number of Firms	Mean	Median	Minimum	Maximum
Production and Integrated					
Small	79	-0.13%	-0.03%	-2.96%	<0.00%
Large	49	-0.02%	-0.02%	-0.17%	0.06%
Subtotal	128	-0.09%	-0.02%	-2.96%	0.06%
Pipeline					
Small	11	<0.00%	<0.01%	<0.01%	0.01%
Large	36	0.01%	<0.01%	<0.01%	0.04%
Subtotal	47	0.01%	<0.01%	<0.01%	0.04%
Processing					
Small	39	0.01%	<0.01%	<0.01%	0.05%
Large	23	<0.00%	<0.01%	<0.01%	0.05%
Subtotal	62	0.01%	<0.01%	<0.01%	0.05%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	<0.01%	<0.01%	<0.01%	0.01%
Subtotal	13	<0.01%	<0.01%	<0.01%	0.01%
Total					
Small	**129**	**-0.08%**	**-0.01%**	**-2.96%**	**0.05%**
Large	**121**	**-0.01%**	**<0.01%**	**-0.17%**	**0.06%**
Total	**250**	**-0.04%**	**<0.01%**	**-2.96%**	**0.06%**

The mean cost-sales ratio for all businesses when estimated product recovery is included is in the sample is -0.04 percent, with a median ratio of less than 0.01 percent, a minimum of -2.96 percent, and a maximum of 0.06 percent (Table 7-24). For small firms in the sample, the mean and median cost-sales ratios are -0.08 percent and -0.01 percent, respectively, with a minimum of -2.96 percent and a maximum of 0.05 percent (Table 7-24). Each of these statistics indicates that, when considered in the aggregate, impacts are small on small business when the estimated revenue from additional natural gas product recovery are included, the reverse of the conclusion found when these revenues are excluded.

Meanwhile, Table 7-25 presents the distribution of estimated cost-sales ratios for the small firms in our sample with and without including estimates of the expected natural gas product recover from implementing controls. When revenues estimates are included, all 129

firms (100 percent) have estimated cost-sales ratios less than 1 percent. While less than 1 percent, the highest cost-sales ratios for small firms in the sample experiencing impacts are largely driven by costs accruing to processing and pipeline firms. That said, the incremental costs imposed on firms that process natural gas or transport natural gas via pipelines are not estimated to create significant impacts on a cost-sales ratio basis at the firm-level.

Table 7-25 Impact Levels of Proposed NSPS on Small Firms as a Percent of Small Firms in Sample, With and Without Revenues from Additional Natural Gas Product Recovery

	Without Estimated Revenues from Natural Gas Product Recovery		With Estimated Revenues from Natural Gas Product Recovery	
Impact Level	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected	Number of Small Firms in Sample Estimated to be Affected	% of Small Firms in Sample Estimated to be Affected
C/S Ratio less than 1%	109	84.5%	129	100.00%
C/S Ratio 1-3%	11	8.5%	0	0.00%
CS Ratio greater than 3%	9	7.0%	0	0.00%

When the estimated revenues from product recovery are not included in the analysis, 11 firms (about 9 percent) are estimated to have sales test ratios between 1 and 3 percent. Nine firms (about 7 percent) are estimated to have sales test ratios greater than 3 percent. These results noted, the exclusion of product recovery is somewhat artificial. While the mean engineering compliance costs and revenues estimates are valid, drawing on the means ignores the distribution around the mean estimates, which risks masking effects. Because of this risk, the following section offers a qualitative discussion of small entities with regard to obtaining REC services, the validity of the cost and performance of RECs for small firms, as well as offers a discussion about whether older equipment, which may be disproportionately owned and operated be smaller producers, would be affected by the proposed NSPS.

7.4.3.3 Small Entity Impact Analysis, Proposed NSPS, Additional Qualitative Discussion

3.5.3.3.1 Small Entities and Reduced Emissions Completions

Because REC requirements of the proposed NSPS are expected to contribute the large majority of engineering compliance costs, it is important to examine these requirements more closely in the context small entities. Important issues to resolve are the scale of REC costs within a drilling project, how the payment system for recovered natural gas functions, whether small entities pursue particular "niche" strategies that may influence the costs or performance in a way that makes the estimates costs and revenues invalid.

According to the most recent natural gas well cost data from EIA, the average cost of drilling and completing a producing natural gas well in 2007 was about $4.8 million (adjusted to 2008 dollars). This average includes lower cost wells that may be relatively shallow or are not hydraulically fractured. Hydraulically fractured wells in deep formations may cost up to $10 million. RECs contracted from a service provider are estimated to cost $33,200 (in 2008 dollars) or roughly 0.3%-0.7% of the typical cost of a drilling and completing a natural gas well. As this range does not include revenues expected from natural gas and hydrocarbon condensate recovery expected to offset REC implementation costs, REC costs likely represent a small increment of the overall burden of a drilling project.

To implement an REC, a service provider, which may itself be a small entity, is typically contracted to bring a set of equipment to the well pad temporarily to capture the stream that would otherwise be vented to the atmosphere. Typically, service providers are engaged in a long term drilling program in a particular basin covering multiple wells on multiple well pads. For gas captured and sold to the gathering system, Lease Automatic Custody Transfer (LACT) meters are normally read daily automatically, and sales transactions are typically settled at the end of the month. Invoices from service providers are generally delivered in 30-day increments during the well development time period, as well as at the end of the working contract for that well pad. The conclusion from the information, based on the available information, in most cases, the owner/operator incurs the REC cost within the same 30 day period that the owner/operator receives revenue as a result of the REC.

We assume small firms are performing RECs in CO and WY, as in many instances RECs are required under state regulation. In addition to State regulations, some companies are implementing RECs voluntarily such as through participation in the EPA Natural Gas STAR Program and the focus of recent press reports.

As described in more detail below, many small independent E&P companies often do not conduct any of the actual field work. These firms will typically contract the drilling, completion, testing, well design, environmental assessment, and maintenance. Therefore, we believe it is likely that small independent E&P firms will contract for RECs from service providers if required to perform RECs. An important reminder is that performing a REC is a straightforward and inexpensive extension of drilling, completion, and testing activities.

To the extent that very small firms may specialize in operating relatively few low-producing stripper wells, it is important to ask whether low-producing wells are likely candidates for re-fracturing/re-completion and, if so, whether the expected costs and revenues would be valid. These marginal gas wells are likely to be older and in conventional formations, and as such are unlikely to be good candidates for re-fracturing/completion. To the extent the marginal wells may be good candidates for re-fracturing/completion, the REC costs are valid estimates. The average REC cost is valid for RECs performed on any well, regardless of the operator size. The reason for this is that the REC service is contracted out to specialty service providers who charge daily rates for the REC equipment and workers. The cost is not related to any well characteristic.

Large operators may receive a discount for offering larger contracts which help a service provider guarantee that REC equipment will be utilized. However, we should note that the existence of a potential discount for larger contracts is based on a strong assumption; we do not have evidence to support this assumption. Since contracting REC equipment is analogous to contracting for drilling equipment, completion equipment, etc., the premium would likely be in the same range as other equipment contracted by small operators. Since the REC cost is a small portion of the overall well drilling and completion cost, the effect of any bulk discount disparity between large and small operators will be small, if in fact it does exist.

Although small operators may own the majority of marginal and stripper wells, they will make decisions based on economics just as any sized company would. For developing a new well, any sized company will expect a return on their investment meaning the potential for sufficient gas, condensate, and/or oil production to pay back their investment and generate a return that exceeds alternative investment opportunities. Therefore, small or large operators that are performing hydraulic fracture completions will experience the same distribution of REC performance. For refracturing an existing well, the well must be a good candidate to respond to the re-fracture/completion with a production increase that merits the investment in the re-fracture/completion.

Plugging and abandoning wells is complex and costly, so sustaining the productivity of wells is important for maximizing the exploitation of proven domestic resources. However, many marginal gas wells are likely to be older and in conventional formations, and as such are unlikely to be good candidates for re-fracturing/completion, which means they are likely unaffected by the proposed NSPS.

3.5.3.3.2 Age of Equipment and Proposed Regulations

Given a large fraction of domestic oil and natural gas production is produced from older and generally low productivity wells, it is important to examine whether the proposed requirements might present impediments to owners and operators of older equipment. The NSPS is a standard that applies to new or modified sources. Because of this, NSPS requirements target new or modified affected facilities or equipment, such as processing plants and compressors. While the requirements may apply to modifications of existing facilities, it is important to discuss well completion-related requirements aside from other requirements in the NSPS distinctly.

Excluding well completion requirements from the cost estimates, the non-completion NSPS requirements (related to equipment leaks at processing plants, reciprocating and centrifugal compressors, pneumatic controllers, and storage vessels) are estimated to require $27 million in annualized engineering costs. EPA also estimates that the annualized costs of these requirements will be mostly if not fully offset by revenues expected from natural gas recovery. EPA does not expect these requirements to disproportionately affect producers with older

equipment. Meanwhile, the REC and emissions combustion requirements in the proposed NSPS relate to well completion activities at new hydraulically fractured natural gas wells and existing wells which are recompleted after being fractured or re-fractured. These requirements constitute the bulk of the expected engineering compliance expenditures (about $710 million in annualized costs) and expected revenues from natural gas product recovery (about $760 million in revenues, annually).

While age of the well and equipment may be an important factor for small and large producers in determining whether it is economical to fracture or re-fracture an existing well, this equipment is unlikely to be subject to the NSPS. To comply with completion-related requirements, producers are likely to rely heavily on portable and temporary completion equipment brought to the wellpad over a short period of time (a few days to a few weeks) to capture and combust emissions that are otherwise vented. The equipment at the wellhead—newly installed in the case of new well completions or already in place and operating in the case of existing wells—is not likely to be subject to the NSPS requirement.

7.4.3.4 Small Entity Impact Analysis, Proposed NSPS, Screening Analysis Conclusion

The number of significantly impacted small businesses is unlikely to be sufficiently large to declare a SISNOSE. Our judgment in this determination is informed by the fact that many affected firms are expected to receive revenues from the additional natural gas and condensate recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from completion-related activities, we expect the impact on well-related compliance costs to be significantly mitigated. This conclusion is enhanced because the returns to reduced emissions completion activities occur without a significant time lag between implementing the control and obtaining the recovered product unlike many control options where the emissions reductions accumulate over long periods of time; the reduced emission completions and recompletions occur over a short span of time, during which the additional product recovery is also accomplished.

7.4.4 Small Entity Economic Impact Analysis, Proposed NESHAP Amendments

The proposed NESHAP amendments will affect facilities operating three types of equipment: glycol dehydrators at production facilities, glycol dehydrators at transmission and compression facilities, and storage vessels. We identified likely affected facilities in the National Emissions Inventory (NEI) and estimated the number of newly required controls of each type that would be required by the NESHAP amendments for each facility. We then used available data sources to best identify the ultimate owner of the equipment that would likely require new controls and linked facility-level compliance cost estimates to firm-level employment and revenue data. These data were then used to calculate an estimated compliance costs to revenues ratio to identify small businesses that might be significantly impacted by the NESHAP.

While we were able to identify the owners all but 14 facilities likely to be affected, we could not obtain employment and revenue levels for all of these firms. Overall, we expect about 447 facilities to be affected, and these facilities are owned by an estimated 160 firms. We were unable to obtain financial information on 42 (26 percent) of these firms due to inadequate data. In some instances, firms are private, and financial data is not available. In other instance, firms may no longer exist, since NEI data are not updated continuously. From the ownership information and compliance cost estimates from the engineering analysis, we estimated total compliance cost per firm.

Of the 118 firms for which we have financial information, we identified 62 small firms and 56 large firms that would be affected by the NESHAP amendments. Annual compliance costs for small firms are estimated at $3.0 million (18 percent of the total compliance costs), and annual compliance costs for large firms are estimated at $10.7 million (67 percent of the total compliance costs). The facilities for which we were unable to identify the ultimate owners, employment, and revenue levels would have an estimated annual compliance cost of $2.3 million (15 percent of the total). All figures are in 2008 dollars.

The average estimated annualized compliance cost for the 62 small firms identified in the dataset is $48,000, while the mean annual revenue figure for the same firms is over $120 million, or less than 1 percent for a average sales-test ratio for all 62 firms (Table 7-26). The median

sale-test ratio for these firms is smaller at 0.14 percent. Large firms are likely to see an average of $190,000 in annual compliance costs, whereas average revenue for these firms exceeds $30 billion since this set of firms includes many of the very large, integrated energy firms. For large firms, the average sales-test ratio is about 0.01 percent, and the median sales-test ratio is less than 0.01 percent (Table 7-26).

Table 7-26 Summary of Sales Test Ratios for Firms Affected by Proposed NESHAP Amendments

Firm Size	No. of Known Affected Firms	% of Total Known Affected Firms	Mean C/S Ratio	Median C/S Ratio	Min. C/S Ratio	Max. C/S Ratio
Small	62	53%	0.62%	0.14%	< 0.01%	6.2%
Large	56	47%	0.01%	< 0.01%	< 0.01%	0.4%
All	118	100%	0.34%	0.02%	< 0.01%	6.2%

Among the small firms, 52 of the 62 (84 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile 10 firms (16 percent) are likely to have impacts greater than 1 percent (Table 7-27). Four of these 10 firms are likely to have impacts greater than 3 percent (Table 7-27) While these 10 firms might receive significant impacts from the proposed NESHAP amendments, they represent a very small slice of the oil and gas industry in its entirety, less than 0.2 percent of the estimated 6,427 small firms in NAICS 211 (Table 7-27).

Table 7-27 Affected Small Firms as a Percent of Small Firms Nationwide, Proposed NESHAP amendments

Firm Size	Number of Small Firms Affected Nationwide	% of Small Firms Affected Nationwide	Affected Firms as a % of National Firms (6,427)
C/S Ratio less than 1%	52	83.9%	0.81%
C/S Ratio 1-3%	6	9.7%	0.09%
CS Ratio greater than 3%	4	6.5%	0.06%

Screening Analysis Conclusion: While there are significant impacts on small business, the analysis shows that a substantial number of small firms are not impacted. Based upon the analysis in this section, we presume there is no SISNOSE arising from the proposed NESHAP amendments.

7.5 References

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EPA United States Environmental Protection Agency

Climate Change

Human Health Impacts & Adaptation

climatechange/impacts-adaptation/health.html#adapt



Climate Impacts on Human Health

Adaptation Examples in Human Health

Weather and climate play a significant role in people's health. Changes in climate affect the average weather conditions that we are accustomed to. Warmer average temperatures will likely lead to hotter days and more frequent and longer heat waves. This could increase the number of heat-related illnesses and deaths. Increases in the frequency or severity of extreme weather events such as storms could increase the risk of dangerous flooding, high winds, and other direct threats to people and property. Warmer temperatures could increase the concentrations of unhealthy air and water pollutants. Changes in temperature, precipitation patterns, and extreme events could enhance the spread of some diseases.

ON THIS PAGE

Impacts from Heat Waves
Impacts from Extreme Weather Events
Impacts from Reduced Air Quality
Impacts from Climate-Sensitive Diseases
Other Heath Linkages

Key Points

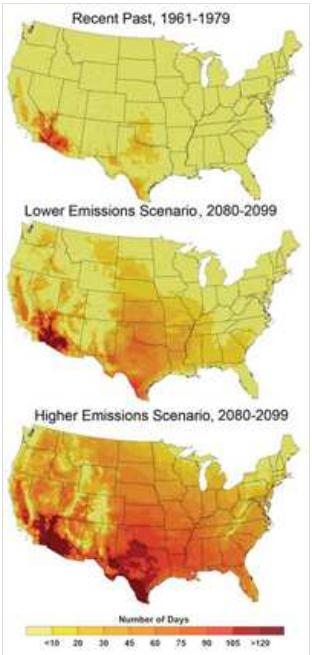
- A warmer climate is expected to both increase the risk of heat-related illnesses and death and worsen conditions for air quality.
- Climate change will likely increase the frequency and strength of extreme events (such as floods, droughts, and storms) that threaten human safety and health.
- Climate changes may allow some diseases to spread more easily.



Sun setting over a city on a hot day.
Source: EPA (2010)

The impacts of climate change on health will depend on many factors. These factors include the effectiveness of a community's public health and safety systems to address or prepare for the risk and the behavior, age, gender, and economic status of individuals affected. Impacts will likely vary by region, the sensitivity of populations, the extent and length of exposure to climate change impacts, and society's ability to adapt to change.

Although the United States has well-developed public health systems (compared with those of many developing countries), climate change will still likely affect many Americans. In addition, the impacts of climate change on public health around the globe could have important consequences for the United States. For example, more frequent and intense storms may require more disaster relief and declines in agriculture may increase food shortages.



View enlarged image

The number of 100-degree days per year is projected to increase.
Source: USGCRP (2009)

Impacts from Heat Waves

Heat waves can lead to heat stroke and dehydration, and are the most common cause of weather-related deaths. [1] [2] Excessive heat is more likely to impact populations in northern latitudes where people are less prepared to cope with excessive temperatures. Young children, older adults, people with medical conditions, and the poor are more vulnerable than others to heat-related illness. The share of the U.S. population composed of adults over age 65 is currently 12%, but is projected to grow to 21% by 2050, leading to a larger vulnerable population. [1]

Climate change will likely lead to more frequent, more severe, and longer heat waves in the summer (see 100-degree-days figure), as well as less severe cold spells in the winter. A recent assessment of the science suggests that increases in heat-related deaths due to climate change would outweigh decreases in deaths from cold-snaps. [1]

Urban areas are typically warmer than their rural surroundings. Climate change could lead to even warmer temperatures in cities. This would increase the demand for electricity in the summer to run air conditioning, which in turn would increase air pollution and greenhouse gas emissions from power plants. The impacts of future heat waves could be especially severe in

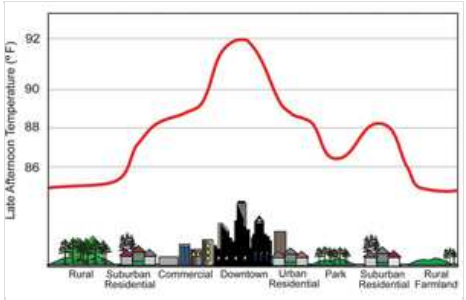
Related Links

EPA:

- Climate Change Indicators in the United States
- Heat Island Effect
- Excessive Heat Events Guidebook
- Global Change Research Program
- Climate Change and Children's Health
- Climate Change and Health Effects on Older Adults
- *Assessment of the Impacts of Global Change on Regional U.S. Air Quality: A Synthesis of Climate Change Impacts on Ground-Level Ozone*
- *Our Nation's Air: Status and Trends Through 2008*

Other:

- CDC Climate Change and Public Health
- USGCRP *Synthesis Assessment Product 4.6: Analyses of the Effects of Global Change on Human Health and Welfare and Human Systems*
- IPCC Fourth Assessment Report, Working Group II EXIT Disclaimer
- USGCRP, Global Climate Change Impacts in the United States: Human Health
- NRC America's Climate Choices: Adapting to the Impacts of Climate Change EXIT Disclaimer
- National Institute of Environmental Health Sciences: *A Human Health Perspective on Climate Change* (PDF)
- World Health Organization, *Climate Change and Human Health: Risks and Responses* EXIT Disclaimer



View enlarged image

The "urban heat island" refers to the fact that the local temperature in urban areas is a few degrees higher than the surrounding area. Source: USGCRP (2009)

large metropolitan areas. For example, in Los Angeles, annual heat-related deaths are projected to increase two- to seven-fold by the end of the 21st century, depending on the future growth of greenhouse gas emissions. [1] Heat waves are also often accompanied by periods of stagnant air, leading to increases in air pollution and the associated health effects

Impacts from Extreme Weather Events

The frequency and intensity of extreme precipitation events is projected to increase in some locations, as is the severity (wind speeds and rain) of tropical storms. [1] These extreme weather events could cause injuries and, in some cases, death. As with heat waves, the people most at risk include young children, older adults, people with medical conditions, and the poor. Extreme events can also indirectly threaten human health in a number of ways. For example, extreme events can:

- Reduce the availability of fresh food and water. [2]
- Interrupt communication, utility, and health care services. [2]
- Contribute to carbon monoxide poisoning from portable electric generators used during and after storms. [2]
- Increase stomach and intestinal illness among evacuees. [1]
- Contribute to mental health impacts such as depression and post-traumatic stress disorder (PTSD). [1]



Flooded streets in New Orleans after Hurricane Katrina in 2005. Source: FEMA (2005)

Climate Change Affects Human Health and Welfare

In 2008, the U.S. Global Change Research Program produced a report that analyzed the impacts of global climate change on human health and welfare. The report finds that:

- Many of the expected health effects are likely to fall mostly on the poor, the very old, the very young, the disabled, and the uninsured.
- Climate change will likely result in regional differences in U.S. impacts, due not only to a regional pattern of changes in climate but also to regional variations in the distribution of sensitive populations and the ability of communities to adapt to climate changes.
- Adaptation should begin now, starting with public health infrastructure. Individuals, communities, and government agencies can take steps to moderate the impacts of climate change on human health. (To learn more, see the Health Adaptation section)

Impacts from Reduced Air Quality

Despite significant improvements in U.S. air quality since the 1970s, as of 2008 more than 126 million Americans lived in counties that did not meet national air quality standards. [3]

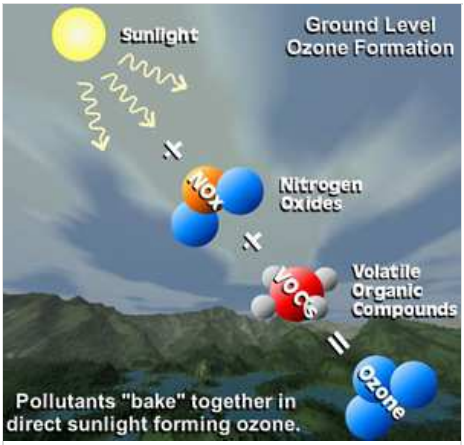
Increases in Ozone

Scientists project that warmer temperatures from climate change will increase the frequency of days with unhealthy levels of ground-level ozone, a harmful air pollutant, and a component in smog. [2] [3]

- Ground-level ozone can damage lung tissue and can reduce lung function and inflame airways. This can increase respiratory symptoms and aggravate asthma or other lung diseases. It is especially harmful to children, older adults, outdoor workers, and those with asthma and other chronic lung diseases. [4]
- Ozone exposure also has been associated with increased susceptibility to respiratory infections, medication use, doctor visits, and emergency department visits and hospital admissions for individuals with lung disease. Some studies suggest that ozone may increase the risk of premature mortality, and possibly even the development of asthma. [1] [2] [3] [5]
- Ground-level ozone is formed when certain air pollutants, such as carbon monoxide, oxides of nitrogen (also called NO_X), and volatile organic compounds, are exposed to each other in sunlight. Ground-level ozone is one of the pollutants in smog. [2] [3]
- Because warm, stagnant air tends to increase the formation of ozone, climate change is likely to increase levels of ground-level ozone in already-polluted areas of the United States and increase the number of days with poor air quality. [1] If emissions of air pollutants remain fixed at today's levels until 2050, warming from climate change alone could increase the number of Red Ozone Alert Days (when the air is unhealthy for everyone) by 68% in the 50 largest eastern U.S. cities. [1] (See Box below "EPA Report on Air Quality and Climate Change.")



Smog in Los Angeles decreases visibility and can be harmful to human health. Source: California Air Resources Board (2011)



Ozone chemistry. Source: NASA (2012)

Changes in Fine Particulate Matter

Particulate matter is the term for a category of extremely small particles and liquid droplets suspended in the atmosphere. Fine particles include particles smaller than 2.5 micrometers (about one ten-thousandth of an inch). These particles may be emitted directly or may be formed in the atmosphere from chemical reactions of gases such as sulfur dioxide, nitrogen dioxide, and volatile organic compounds.

- Inhaling fine particles can lead to a broad range of adverse health effects, including premature mortality, aggravation of cardiovascular and respiratory disease, development of chronic lung disease, exacerbation of asthma, and decreased lung function growth in children. [6]
- Sources of fine particle pollution include power plants, gasoline and diesel engines, wood combustion, high-temperature industrial processes such as smelters and steel mills, and forest fires. [6]

Due to the variety of sources and components of fine particulate matter, scientists do not yet know whether climate change will increase or decrease particulate matter concentrations across the United States. [7] [8] A lot of particulate matter is cleaned from the air by rainfall, so increases in precipitation could have a beneficial effect. At the same time, other climate-related changes in stagnant air episodes, wind patterns, emissions from vegetation and the chemistry of atmospheric pollutants will likely affect particulate matter levels. [2] Climate change will also affect particulates through changes in wildfires, which are expected to become more frequent and intense in a warmer climate. [7]

Changes in Allergens

Climate change may affect allergies and respiratory health. [4] The spring pollen season is already occurring earlier in the United States due to climate change. The length of the season may also have increased. In addition, climate change may facilitate the spread of ragweed, an invasive plant with very allergenic pollen. Tests on ragweed show that increasing carbon dioxide concentrations and temperatures would increase the amount and timing of ragweed pollen production. [1] [2] [9]

Impacts from Climate-Sensitive Diseases

Changes in climate may enhance the spread of some diseases. [1] Disease-causing agents, called pathogens, can be transmitted through food, water, and animals such as deer, birds, mice, and insects. Climate change could affect all of these transmitters.

Food-borne Diseases

- Higher air temperatures can increase cases of salmonella and other bacteria-related food poisoning because bacteria grow more rapidly in warm environments. These diseases can cause gastrointestinal distress and, in severe cases, death. [1]
- Flooding and heavy rainfall can cause overflows from sewage treatment plants into fresh water sources. Overflows could contaminate certain food crops with pathogen-containing feces. [1]

Water-borne Diseases

- Heavy rainfall or flooding can increase water-borne parasites such as *Cryptosporidium* and *Giardia* that are sometimes found in drinking water. [1] These parasites can cause gastrointestinal distress and in severe cases, death.
- Heavy rainfall events cause stormwater runoff that may contaminate water bodies used for recreation (such as lakes and beaches) with other bacteria. [9] The most common illness contracted from contamination at beaches is gastroenteritis, an inflammation of the stomach and the intestines that can cause symptoms such as vomiting, headaches, and fever. Other minor illnesses include ear, eye, nose, and throat infections. [2]

EPA Report on Air Quality and Climate Change

Improving America's air quality is one of EPA's top priorities. EPA's Global Change Research Program is investigating the potential consequences of climate change on U.S. air quality. A recent interim assessment finds that:

- Climate change could increase surface-level ozone concentrations in areas where pollution levels are already high.
- Climate change could make U.S. air quality management more difficult.
- Policy makers should consider the potential impacts of climate change on air quality when making air quality management decisions.

Animal-borne Diseases

- The geographic range of ticks that carry Lyme disease is limited by temperature. As air temperatures rise, the range of these ticks is likely to continue to expand northward. [9] Typical symptoms of Lyme disease include fever, headache, fatigue, and a characteristic skin rash.
- In 2002, a new strain of West Nile virus, which can cause serious, life-altering disease, emerged in the United States. Higher temperatures are favorable to the survival of this new strain. [1]

The spread of climate-sensitive diseases will depend on both climate and non-climate factors. The United States has public health infrastructure and programs to monitor, manage, and prevent the spread of many diseases. The risks for climate-sensitive diseases can be much higher in poorer countries that have less capacity to prevent and treat illness. [9] For more information, please visit the International Impacts & Adaptation page.



Mosquitoes favor warm, wet climates and can spread diseases such as West Nile virus.

Other Heath Linkages

Other linkages exist between climate change and human health. For example, changes in temperature and precipitation, as well as droughts and floods, will likely affect agricultural yields and production. In some regions of the world, these impacts may compromise food security and threaten human health through malnutrition, the spread of infectious diseases, and food poisoning. The worst of these effects are projected to occur in developing countries, among vulnerable populations. [9] Declines in human health in other countries might affect the United States through trade, migration and immigration and have implications for national security. [1] [2]

Although the impacts of climate change have the potential to affect human health in the United States and around the world, there is a lot we can do to prepare for and adapt to these changes. Learn about how we can adapt to climate impacts on health.

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WCMS
Last updated on Thursday, June 14, 2012

EPA United States Environmental Protection Agency

Sulfur Dioxide
Health

Current scientific evidence links short-term exposures to SO_2, ranging from 5 minutes to 24 hours, with an array of adverse respiratory effects including bronchoconstriction and increased asthma symptoms. These effects are particularly important for asthmatics at elevated ventilation rates (e.g., while exercising or playing.)

Studies also show a connection between short-term exposure and increased visits to emergency departments and hospital admissions for respiratory illnesses, particularly in at-risk populations including children, the elderly, and asthmatics.

EPA's National Ambient Air Quality Standard for SO_2 is designed to protect against exposure to the entire group of sulfur oxides (SOx). SO_2 is the component of greatest concern and is used as the indicator for the larger group of gaseous sulfur oxides (SOx). Other gaseous sulfur oxides (e.g. SO3) are found in the atmosphere at concentrations much lower than SO_2.

Emissions that lead to high concentrations of SO_2 generally also lead to the formation of other SOx. Control measures that reduce SO_2 can generally be expected to reduce people's exposures to all gaseous SOx. This may have the important co-benefit of reducing the formation of fine sulfate particles, which pose significant public health threats.

SOx can react with other compounds in the atmosphere to form small particles. These particles penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory disease, such as emphysema and bronchitis, and can aggravate existing heart disease, leading to increased hospital admissions and premature death. EPA's NAAQS for particulate matter (PM) are designed to provide protection against these health effects.

Last updated on Thursday, July 12, 2012

EPA United States Environmental Protection Agency

Particulate Matter (PM)
Health

The size of particles is directly linked to their potential for causing health problems. Small particles less than10 micrometers in diameter pose the greatest problems, because they can get deep into your lungs, and some may even get into your bloodstream.

Exposure to such particles can affect both your lungs and your heart. Small particles of concern include "inhalable coarse particles" (such as those found near roadways and dusty industries), which are larger than 2.5 micrometers and smaller than 10 micrometers in diameter; and "fine particles" (such as those found in smoke and haze), which are 2.5 micrometers in diameter and smaller.

The Clean Air Act requires EPA to set air quality standards to protect both public health and the public welfare (e.g. visibility, crops and vegetation). Particle pollution affects both.

Health Effects

Particle pollution - especially fine particles - contains microscopic solids or liquid droplets that are so small that they can get deep into the lungs and cause serious health problems. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including:

- premature death in people with heart or lung disease,
- nonfatal heart attacks,
- irregular heartbeat,
- aggravated asthma,
- decreased lung function, and
- increased respiratory symptoms, such as irritation of the airways, coughing or difficulty breathing.

People with heart or lung diseases, children and older adults are the most likely to be affected by particle pollution exposure. However, even if you are healthy, you may experience temporary symptoms from exposure to elevated levels of particle pollution. For more information about asthma, visit www.epa.gov/asthma.

Environmental Effects

Visibility impairment
Fine particles ($PM_{2.5}$) are the main cause of reduced visibility (haze) in parts of the United States, including many of our treasured national parks and wilderness areas. For more information about visibility, visit www.epa.gov/visibility.

Environmental damage
Particles can be carried over long distances by wind and then settle on ground or water. The effects of this settling include: making lakes and streams acidic; changing the nutrient balance in coastal waters and large river basins; depleting the nutrients in soil; damaging sensitive forests and farm crops; and affecting the diversity of ecosystems. More information about the effects of particle pollution and acid rain.

Aesthetic damage
Particle pollution can stain and damage stone and other materials, including culturally important objects such as statues and monuments. More information about the effects of particle pollution and acid rain.

You will need Adobe Acrobat Reader to view the Adobe PDF files on this page. See EPA's PDF page for more information about getting and using the free Acrobat Reader.

For more information on particle pollution, health and the environment, visit:

Particle Pollution and Your Health (PDF) (2pp, 320k): Learn who is at risk from exposure to particle pollution, what health effects you may experience as a result of particle exposure, and simple measures you can take to reduce your risk.

How Smoke From Fires Can Affect Your Health: It's important to limit your exposure to smoke – especially if you may be susceptible. This publication provides steps you can take to protect your health.

Integrated Science Assessment for Particulate Matter (December 2009): This comprehensive assessment of scientific data about the health and environmental effects of particulate matter is an important part of EPA's review of its particle pollution standards.

Last updated on Friday, June 15, 2012

EPA United States Environmental Protection Agency

Visibility
Basic Information

How far can you see?

Every year there are over 280 million visitors to our nation's most treasured parks and wilderness areas. Unfortunately, many visitors aren't able to see the spectacular vistas they expect. During much of the year a veil of white or brown haze hangs in the air blurring the view. Most of this haze is not natural. It is air pollution, carried by the wind often many hundreds of miles from where it originated.

In our nation's scenic areas, the visual range has been substantially reduced by air pollution. In eastern parks, average visual range has decreased from 90 miles to 15-25 miles. In the West, visual range has decreased from 140 miles to 35-90 miles.

What is haze?

Haze is caused when sunlight encounters tiny pollution particles in the air. Some light is absorbed by particles. Other light is scattered away before it reaches an observer. More pollutants mean more absorption and scattering of light, which reduce the clarity and color of what we see. Some types of particles such as sulfates, scatter more light, particularly during humid conditions.

Where does haze-forming pollution come from?

Air pollutants come from a variety of natural and manmade sources. Natural sources can include windblown dust, and soot from wildfires. Manmade sources can include motor vehicles, electric utility and industrial fuel burning, and manufacturing operations. Particulate matter pollution is the major cause of reduced visibility (haze) in parts of the United States, including many of our national parks. Find out more about particulate pollution.

Some haze-causing particles are directly emitted to the air. Others are formed when gases emitted to the air form particles as they are carried many miles from the source of the pollutants.

What else can these pollutants do to you and the environment?

Some of the pollutants which form haze have also been linked to serious health problems and environmental damage. Exposure to very small particles in the air have been linked with increased respiratory illness, decreased lung function, and even premature death. In addition, particles such as nitrates and sulfates contribute to acid rain formation which makes lakes, rivers, and streams unsuitable for many fish, and erodes buildings, historical monuments, and paint on cars.

You will need Adobe Acrobat Reader to view the Adobe PDF files on this page. See EPA's PDF page for more information about getting and using the free Acrobat Reader.

How can I learn more about visibility?

How Air Pollution Affects the View (PDF) (2 pp, 793 KB) - EPA brochure describing the health and environmental effects of haze.

Introduction to Visibility (PDF) (79 pp., 3.3 MB) - Report by William Malm, National Park Service and Colorodo State Institute for Research on the Atmosphere

What other Federal agencies address visibility?

- National Park Service EXIT Disclaimer
- U.S. Forest Service EXIT Disclaimer
- U.S. Fish and Wildlife Service EXIT Disclaimer

Last updated on Thursday, May 31, 2012

DOE/EIA-0581(2009)

The National Energy Modeling System: An Overview 2009

October 2009

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

This publication is on the WEB at:
www.eia.doe.gov/oiaf/aeo/overview/

This report was prepared by the Energy Information Administration, the independent statistical and analytical agency within the U.S. Department of Energy. The information contained herein should be attributed to the Energy Information Administration and should not be construed as advocating or reflecting any policy position of the Department of Energy or any other organization.

Preface

The National Energy Modeling System: An Overview 2009 provides a summary description of the National Energy Modeling System, which was used to generate the projections of energy production, demand, imports, and prices through the year 2030 for the *Annual Energy Outlook 2009, (DOE/EIA-0383(2009*)), released in March 2009. *AEO2009* presents national projections of energy markets for five primary cases—a reference case and four additional cases that assume higher and lower economic growth and higher and lower world oil prices than in the reference case. The Overview presents a brief description of the methodology and scope of each of the component modules of NEMS. The model documentation reports listed in the appendix of this document provide further details.

The Overview was prepared by the Energy Information Administration, Office of Integrated Analysis and Forecasting under the direction of John J. Conti (john.conti@eia.doe.gov, 202/586-2222), Director, Office of Integrated Analysis and Forecasting; Paul D. Holtberg (paul.holtberg@eia.doe.gov, 202/586-1284), Director of the Demand and Integration Division; Joseph A. Beamon (jbeamon@eia.doe.gov, 202/586-2025), Director of the Coal and Electric Power Division; A. Michael Schaal (michael,schaal@eia.doe.gov, 202/586-5590), Director of the Oil and Gas Division; Glen E. Sweetnam (glen.sweetnam@eia.doe.gov, 202-586-2188), Director, International, Economic, and Greenhouse Gases Division; and Andy S. Kydes (akydes@eia.doe.gov, 202/586-2222), Senior Technical Advisor.

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AEO2009 is available on the EIA Home Page on the Internet (http://www.eia.doe.gov/oiaf/aeo/index.html). Assumptions underlying the projections are available in Assumptions to the Annual Energy Outlook 2009 at http://www.eia.doe.gov/oiaf/aeo/assumption/index.html. Tables of regional projections and other underlying details of the reference case are available at http://www.eia.doe.gov/oiaf/aeo/supplement/index.html. Model documentation reports and The National Energy Modeling System: An Overview 2009 are also available on the Home Page at http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model documentation.

For ordering information and for questions on energy statistics, please contact EIA's National Energy Information Center.

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Introduction

Introduction

The National Energy Modeling System (NEMS) is a computer-based, energy-economy modeling system of U.S. through 2030. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS was designed and implemented by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE).

The National Energy Modeling System: An Overview 2009 provides an overview of the structure and methodology of NEMS and each of its components. This chapter provides a description of the design and objectives of the system, followed by a chapter on the overall modeling structure and solution algorithm. The remainder of the report summarizes the methodology and scope of the component modules of NEMS. The model descriptions are intended for readers familiar with terminology from economic, operations research, and energy modeling. More detailed model documentation reports for all the NEMS modules are also available from EIA (Appendix, "Bibliography").

Purpose of NEMS

NEMS is used by EIA to project the energy, economic, environmental, and security impacts on the United States of alternative energy policies and different assumptions about energy markets. The projection horizon is approximately 25 years into the future. The projections in *Annual Energy Outlook 2009 (AEO2009)* are from the present through 2030. This time period is one in which technology, demographics, and economic conditions are sufficiently understood in order to represent energy markets with a reasonable degree of confidence. NEMS provides a consistent framework for representing the complex interactions of the U.S. energy system and its response to a wide variety of alternative assumptions and policies or policy initiatives. As an annual model, NEMS can also be used to examine the impact of new energy programs and policies.

Energy resources and prices, the demand for specific energy services, and other characteristics of energy markets vary widely across the United States. To address these differences, NEMS is a regional model. The regional disaggregation for each module reflects the availability of data, the regional format typically used to analyze trends in the specific area, geology, and other factors, as well as the regions determined to be the most useful for policy analysis. For example, the demand modules (e.g., residential, commercial, industrial and transportation) use the nine Census divisions, the Electricity Market Module uses 15 supply regions based on the North American Electric Reliability Council (NERC) regions, the Oil and Gas Supply Modules use 12 supply regions, including 3 offshore and 3 Alaskan regions, and the Petroleum Market Module uses 5 regions based on the Petroleum Administration for Defense Districts.

Baseline projections are developed with NEMS and published annually in the *Annual Energy Outlook (AEO*). In accordance with the requirement that EIA remain policy-neutral, the *AEO* projections are generally based on Federal, State, and local laws and regulations in affect at the time of the projection. The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require implementing regulations or appropriations of funds that have not been provided or specified in the legislation itself—are not reflected in NEMS. The first version of NEMS, completed in December 1993, was used to develop the projections presented in the *Annual Energy Outlook 1994*. This report describes the version of NEMS used for the *AEO2009*.[1]

The projections produced by NEMS are not considered to be statements of what will happen but of what might happen, given the assumptions and methodologies used. Assumptions include, for example, the estimated size of the economically recoverable resource base of fossil fuels, and changes in world energy supply and demand. The projections are business-as-usual trend estimates, given known technological and demographic trends.

Analytical Capability

NEMS can be used to analyze the effects of existing and proposed government laws and regulations related to energy production and use; the potential impact of new and advanced energy production, conversion, and consumption technologies; the impact and cost of greenhouse gas control; the impact of increased use of renewable energy sources; and the potential savings

1 Energy Information Administration, *Annual Energy Outlook 2009,* DOE/EIA-0383(2009) (Washington, DC, March 2009)

from increased efficiency of energy use; and the impact of regulations on the use of alternative or reformulated fuels.

In addition to producing the analyses in the *AEO*, NEMS is used for one-time analytical reports and papers, such as *An Updated Annual Energy Outlook 2009 Reference Case Reflecting Provisions of the American Recovery and Reinvestment Act and Recent Changes in the Economic Outlook*,[2] which updates the *AEO2009* reference case to reflect the enactment of the American Recovery and Reinvestment Act in February 2009 and to adopt a revised macroeconomic outlook for the U.S. and global economies. The revised *AEO2009* reference case will be used as the starting point for pending and future analyses of proposed energy and environmental legislation. Other analytical papers, which either describe the assumptions and methodology of the NEMS or look at current energy markets issues, are prepared using the NEMS. Many of these papers are published in the Issues In Focus section of the *AEO*. Past and current analyses are available at http://www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_analyes.html.

NEMS has also been used for a number of special analyses at the request of the Administration, U.S. Congress, other offices of DOE and other government agencies, who specify the scenarios and assumptions for the analysis. Some recent examples include:

- *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009*,[3] requested by Chairman Henry Waxman and Chairman Edward Markey to analyze the impacts of H.R. 2454, the American Clean Energy and Security Act of 2009 (ACESA), which was passed by the House of Representatives on June 26, 2009. ACESA is a complex bill that regulates emissions of greenhouse gases through market-based mechanisms, efficiency programs, and economic incentives.
- *Impacts of a 25-Percent Renewable Electricity Standard as Proposed in the American Clean Energy and Security Act*,[4] requested by Senator Markey to analyze the effects of a 25-percent Federal renewable electricity standard (RES) as included in the discussion draft of broader legislation, the American Clean Energy and Security Act.
- *Light-Duty Diesel Vehicles: Efficiency and Emissions Attributes and Market Issues*,[5] requested by Senator Sessions *to* analyze the environmental and energy efficiency attributes of diesel-fueled light-duty vehicles (LDV's), including comparison of the characteristics of the vehicles with those of similar gasoline-fueled, E85-fueled, and hybrid vehicles, as well as a discussion of any technical, economic, regulatory, or other obstacles to increasing the use of diesel-fueled vehicles in the United States.
- *The Impact of Increased Use of Hydrogen on Petroleum Consumption and Carbon Dioxide Emissions*,[6] requested by Senator Dorgan to analyze the impacts on U.S. energy import dependence and emissions reductions resulting from the commercialization of advanced hydrogen and fuel cell technologies in the transportation and distributed generation markets.
- *Analysis of Crude Oil Production in the Arctic National Wildlife Refuge*,[7] requested by Senator Stevens to access the impact of Federal oil and natural gas leasing in the coastal plain of the Arctic National Wildlife Refuge in Alaska.
- *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of*

2 Energy Information Administration, *An Updated Annual Energy Outlook 2009 Reference Case Reflecting Provisions of the American Recovery and Reinvestment Act and Recent Changes in the Economic Outlook*, SR/OIAF/2009-4 (Washington, DC, April 2009).

3 Energy Information Administration, Energy Market and Economic Impacts of H.R. 2454, the American Clean energy and Security Act of 2009, SR/OIAF/2009-05 (Washington, DC, August 2009).

4 Energy Information Administration, *Impacts of a 25-Percent Renewable Electricity Standard as proposed in the American Clean Energy and Security Act Discussion*, SR/OIAF/2009-03 (Washington, DC, April 2009)

5 Energy Information Administration, *Light-Duty Diesel Vehicles: Efficiency and Emissions Attributes and Market Issues*, SR/OIAF/2009-02 (Washington, DC, February 2009).

6 Energy Information Administration, *The Impact of Increased Use of Hydrogen on Petroleum Consumption and Carbon Light-Duty Diesel Vehicles: Efficiency and Emissions Attributes and Market Issues*, SR/OIAF/2008-04 (Washington, DC, September 2008).

7 Energy Information Administration, *Analysis of Crude Oil Production in the Arctic National Wildlife Refuge*, SR/OIAF/2008-03 (Washington, DC, May 2008).

2007,[8] requested by Senators Lieberman, Warner, Inhofe, Voinovich, and Barrasso to analyze the impacts of the greenhouse gas cap-and-trade program that would be established under Title I of S.2191.

- *Energy Market and Economic Impact*s of S.1766, the Low Carbon Economy Act of 2007,[9] requested by Senators Bingaman and Specter to analyze the impact of the mandatory greenhouse gas allowance program under S.1766 designed to maintain covered emissions at approximately 2006 levels in 2020, 1990 levels in 2030, and at least 60 percent below 1990 levels by 2050.

Representations of Energy Market Interactions

NEMS is designed to represent the important interactions of supply and demand in U.S. energy markets. In the United States, energy markets are driven primarily by the fundamental economic interactions of supply and demand. Government regulations and policies can exert considerable influence, but the majority of decisions affecting fuel prices and consumption patterns, resource allocation, and energy technologies are made by private individuals who value attributes other than life cycle costs or companies attempting to optimize their own economic interests. NEMS represents the market behavior of the producers and consumers of energy at a level of detail that is useful for analyzing the implications of technological improvements and policy initiatives.

Energy Supply/Conversion/Demand Interactions

NEMS is a modular system. Four end-use demand modules represent fuel consumption in the residential, commercial, transportation, and industrial sectors, subject to delivered fuel prices, macroeconomic influences, and technology characteristics. The primary fuel supply and conversion modules compute the levels of domestic production, imports, transportation costs, and fuel prices that are needed to meet domestic and export demands for energy, subject to resource base characteristics, industry infrastructure and technology, and world market conditions. The modules interact to solve for the economic supply and demand balance for each fuel. Because of the modular design, each sector can be represented with the methodology and the level of detail, including regional detail, appropriate for that sector. The modularity also facilitates the analysis, maintenance, and testing of the NEMS component modules in the multi-user environment.

Domestic Energy System/Economy Interactions

The general level of economic activity, represented by gross domestic product, has traditionally been used as a key explanatory variable or driver for projections of energy consumption at the sectoral and regional levels. In turn, energy prices and other energy system activities influence economic growth and activity. NEMS captures this feedback between the domestic economy and the energy system. Thus, changes in energy prices affect the key macroeconomic variables—such as gross domestic product, disposable personal income, industrial output, housing starts, employment, and interest rates—that drive energy consumption and capacity expansion decisions.

Domestic/World Energy Market Interactions

World oil prices play a key role in domestic energy supply and demand decision making and oil price assumptions are a typical starting point for energy system projections. The level of oil production and consumption in the U.S. energy system also has a significant influence on world oil markets and prices. In NEMS, an international module represents the response of world oil markets (supply and demand) to assumed world oil prices. The results/outputs of the module are international liquids consumption and production by region, and a crude oil supply curve representing international crude oil similar in quality to West Texas Intermediate that is available to U.S. markets through the Petroleum Market Module (PMM) of NEMS. 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 liquids supply and demand, current investment trends in exploration and development, and long-term resource economics for 221 countries/territories. The oil production estimates include both conventional and unconventional supply recovery technologies.

8 Energy Information Administration, *Energy Market and Economic Impacts of S.2191, the Lieberan-Warner Climate Security Act of 2007*, SR/OIAF/2008-01 (Washington, DC, April 2008).

9 Energy Information Administration, *Energy Market and Economic Impacts of S.1766, the Low Carbon Economy Act of 2007*, SR/OIAF/2007-06 (Washington, DC, January 2008).

Economic Decision Making Over Time

The production and consumption of energy products today are influenced by past investment decisions to develop energy resources and acquire energy-using capital stock. Similarly, the production and consumption of energy in a future time period will be influenced by decisions made today and in the past.

Current investment decisions depend on expectations about future markets. For example, expectations of rising energy prices in the future increase the likelihood of current decisions to invest in more energy-efficient technologies or alternative energy sources. A variety of assumptions about planning horizons, the formation of expectations about the future, and the role of those expectations in economic decision making are applied within the individual NEMS modules.

Technology Representation

A key feature of NEMS is the representation of technology and technology improvement over time. Five of the sectors—residential, commercial, transportation, electricity generation, and refining—include extensive treatment of individual technologies and their characteristics, such as the initial capital cost, operating cost, date of availability, efficiency, and other characteristics specific to the particular technology. For example, technological progress in lighting technologies results in a gradual reduction in cost and is modeled as a function of time in these end-use sectors. In addition, the electricity sector accounts for technological optimism in the capital costs of first-of-a-kind generating technologies and for a decline in cost as experience with the technologies is gained both domestically and internationally. In each of these sectors, equipment choices are made for individual technologies as new equipment is needed to meet growing demand for energy services or to replace retired equipment.

In the other sectors—industrial, oil and gas supply, and coal supply—the treatment of technologies is more limited due to a lack of data on individual technologies. In the industrial sector, only the combined heat and power and motor technologies are explicitly considered and characterized. Cost reductions resulting from technological progress in combined heat and power technologies are represented as a function of time as experience with the technologies grows. Technological progress is not explicitly modeled for the industrial motor technologies. Other technologies in the energy-intensive industries are represented by technology bundles, with technology possibility curves representing efficiency improvement over time. In the oil and gas supply sector, technological progress is represented by econometrically estimated improvements in finding rates, success rates, and costs. Productivity improvements over time represent technological progress in coal production.

External Availability

In accordance with EIA requirements, NEMS is fully documented and archived. EIA has been running NEMS on four EIA terminal servers and several dual-processor personal computers (PCs) using the Windows XP operating system. The archive file provides the source language, input files, and output files to replicate the *Annual Energy Outlook* reference case runs on an identically equipped computer; however, it does not include the proprietary portions of the model, such as the IHS Global Insight, Inc. (formerly DRI-WEFA) macroeconomic model and the optimization modeling libraries. NEMS can be run on a high-powered individual PC as long as the required proprietary software resides on the PC. Because of the complexity of NEMS, and the relatively high cost of the proprietary software, NEMS is not widely used outside of the Department of Energy. However, NEMS, or portions of it, is installed at the Lawrence Berkeley National Laboratory, Oak Ridge National Laboratory, the Electric Power Research Institute, the National Energy Technology Laboratory, the National Renewable Energy Laboratory, several private consulting firms, and a few universities.

Overview of NEMS

Overview of NEMS

NEMS explicitly represents domestic energy markets by the economic decision making involved in the production, conversion, and consumption of energy products. Where possible, NEMS includes explicit representation of energy technologies and their characteristics. Since energy costs, availability, and energy-consuming characteristics vary widely across regions, considerable regional detail is included. Other details of production and consumption are represented to facilitate policy analysis and ensure the validity of the results. A summary of the detail provided in NEMS is shown in Table 1.

Table 1. Characteristics of Selected Modules

Energy Activity	Categories	Regions
Residential Demand	Twenty four end-use services Three housing types Fifty end-use technologies	Nine Census divisions
Commercial demand	Ten end-use services Eleven building types Eleven distributed generation technologies Sixty-three end-use technologies	Nine Census divisions
Industrial demand	Seven energy-intensive industries Eight non-energy-intensive industries Six non-manufacturing industries Cogeneration	Four Census regions, shared to nine Census divisions
Transportation demand	Six car sizes Six light truck sizes Sixty-three conventional fuel-saving technologies for light-duty vehicles Gasoline, diesel, and fourteen alternative-fuel vehicle technologies for light-duty vehicles Twenty vintages for light-duty vehicles Regional, narrow, and wide-body aircraft Six advanced aircraft technologies Light, medium, and heavy freight trucks Thirty-seven advanced freight truck technologies	Nine Census divisions
Electricity	Eleven fossil generation technologies Two distributed generation technologies Eight renewable generation technologies Conventional and advanced nuclear Storage technology to model load shifting Marginal and average cost pricing Generation capacity expansion Seven environmental control technologies	Fifteen electricity supply regions (including Alaska and Hawaii) based on the North American Electric Reliability Council regions and subregions Nine Census divisions for demand Fifteen electricity supply regions
Renewables	Two wind technologies—onshore and offshore—, geothermal, solar thermal, solar photovoltaic, landfill gas, biomass, conventional hydropower	
Oil supply	Lower-48 onshore Lower-48 deep and shallow offshore Alaska onshore and offshore	Six lower 48 onshore regions Three lower 48 offshore regions Three Alaska regions
Natural gas supply	Conventional lower-48 onshore Lower-48 deep and shallow offshore Coalbed methane Gas shales Tight sands	Six lower 48 onshore regions Three lower 48 offshore regions Three Alaska regions
Natural gas transmission and distribution	Core vs. noncore delivered prices Peak vs. off-peak flows and prices Pipeline capacity expansion Pipeline and distributor tariffs Canada, Mexico, and LNG imports and exports Alaska gas consumption and supply	Twelve lower 48 regions Ten pipeline border points Eight LNG import regions
Refining	Five crude oil categories Fourteen product categories More than 40 distinct technologies Refinery capacity expansion	Five refinery regions based on the Petroleum Administration for Defense Districts
Coal supply	Three sulfur categories Four thermal categories Underground and surface mining types Imports and Exports	Fourteen supply regions Fourteen demand regions Seventeen export regions Twenty import regions

Major Assumptions

Each module of NEMS embodies many assumptions and data to characterize the future production, conversion, or consumption of energy in the United States. Two of the more important factors influencing energy markets are economic growth and oil prices.

The *AEO2009* includes five primary fully-integrated cases: a reference case, high and low economic growth cases, and high and low oil price cases. The primary determinant for different economic growth rates are assumptions about growth in the labor force and productivity, while the long-term oil price paths are based on access to and cost of oil from the non-Organization of Petroleum Exporting Countries (OPEC), OPEC supply decisions, and the supply potential of unconventional liquids, as well as the demand for liquids.

In addition to the five primary fully-integrated cases, *AEO2009* includes 34 other cases that explore the impact of varying key assumptions in the individual components of NEMS. Many of these cases involve changes in the assumptions that impact the penetration of new or improved technologies, which is a major uncertainty in formulating projections of future energy markets. Some of these cases are run as fully integrated cases (e.g., integrated 2009 technology case, integrated high technology case, low and high renewables technology cost cases, slow and rapid oil and gas technology cases, and low and high coal cost cases). Others exploit the modular structure of NEMS by running only a portion of the entire modeling system in order to focus on the first-order impacts of changes in the assumptions (e.g., 2009, high, and best available technology cases in the residential and commercial sectors, 2009 and high technology cases in the industrial sector and, low and high technology cases in the transportation sector).

NEMS Modular Structure

Overall, NEMS represents the behavior of energy markets and their interactions with the U.S. economy. The model achieves a supply/demand balance in the end-use demand regions, defined as the nine Census divisions (Figure 1), by solving for the prices of each energy type that will balance the quantities producers are willing to supply with the quantities consumers wish to consume. The system reflects market economics, industry structure, and existing energy policies and regulations that influence market behavior.

NEMS consists of four supply modules (oil and gas, natural gas transmission and distribution, coal market, and renewable fuels); two conversion modules (electricity market and petroleum market); four end-use demand modules (residential demand, commercial demand, industrial demand, and transportation demand); one module to simulate energy/economy interactions (macroeconomic activity); one module to simulate international energy markets (international energy); and one module that provides the mechanism to achieve a general market equilibrium among all the other modules (integrating module). Figure 2 depicts the high-level structure of NEMS.

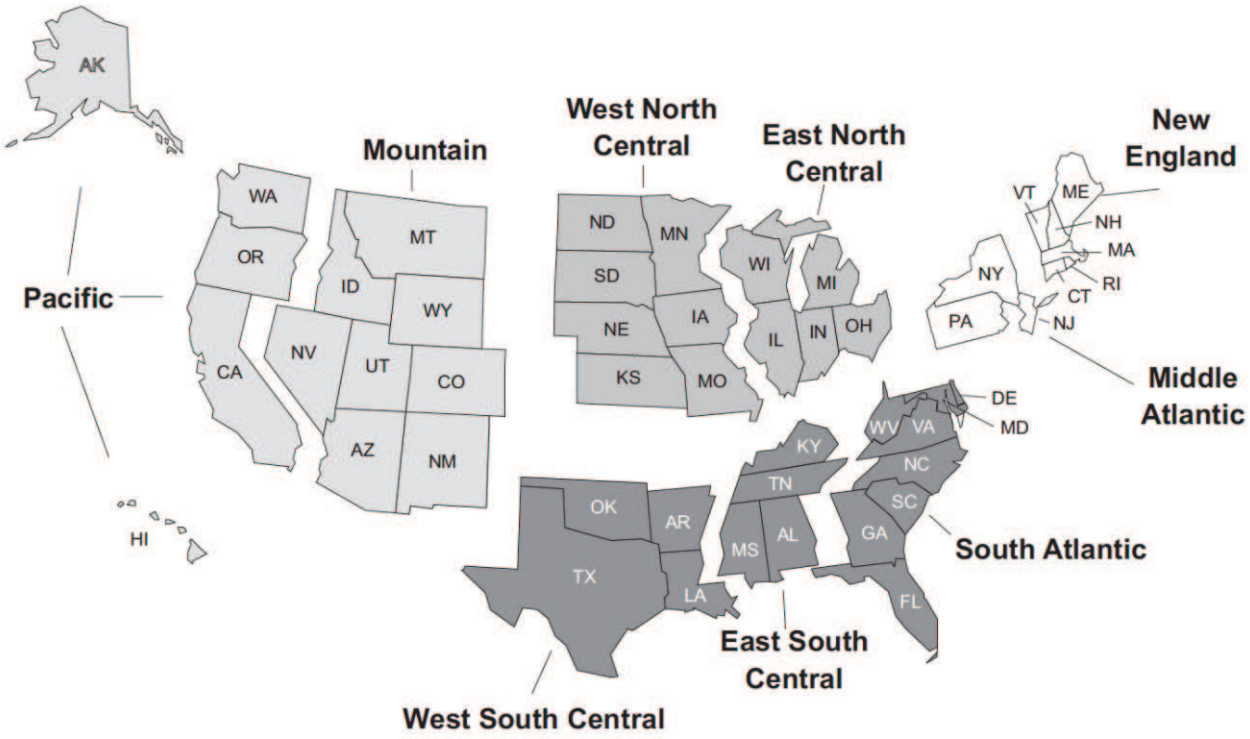
Because energy markets are heterogeneous, a single methodology does not adequately represent all supply, conversion, and end-use demand sectors. The modularity of the NEMS design provides the flexibility for each component of the U.S. energy system to use the methodology and coverage that is most appropriate. Furthermore, modularity provides the capability to execute the modules individually or in collections of modules, which facilitates the development and analysis of the separate component modules. The interactions among these modules are controlled by the integrating module.

The NEMS global data structure is used to coordinate and communicate the flow of information among the modules. These data are passed through common interfaces via the integrating module. The global data structure includes energy market prices and consumption; macroeconomic variables; energy production, transportation, and conversion information; and centralized model control variables, parameters, and assumptions. The global data structure excludes variables that are defined locally within the modules and are not communicated to other modules.

A key subset of the variables in the global data structure is the end-use prices and quantities of fuels that are used to equilibrate the NEMS energy balance in the convergence algorithm. These delivered prices of energy and the quantities demanded are defined by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The regions used for the price and quantity variables in the global data structure are the nine Census divisions. The four Census regions (shown in Figure 1 by breaks between State groups) and nine Census divisions are a common, mainstream level of regionality widely used by EIA and other organizations for data collection and analysis.

Overview of NEMS

Figure 1. Census Division



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

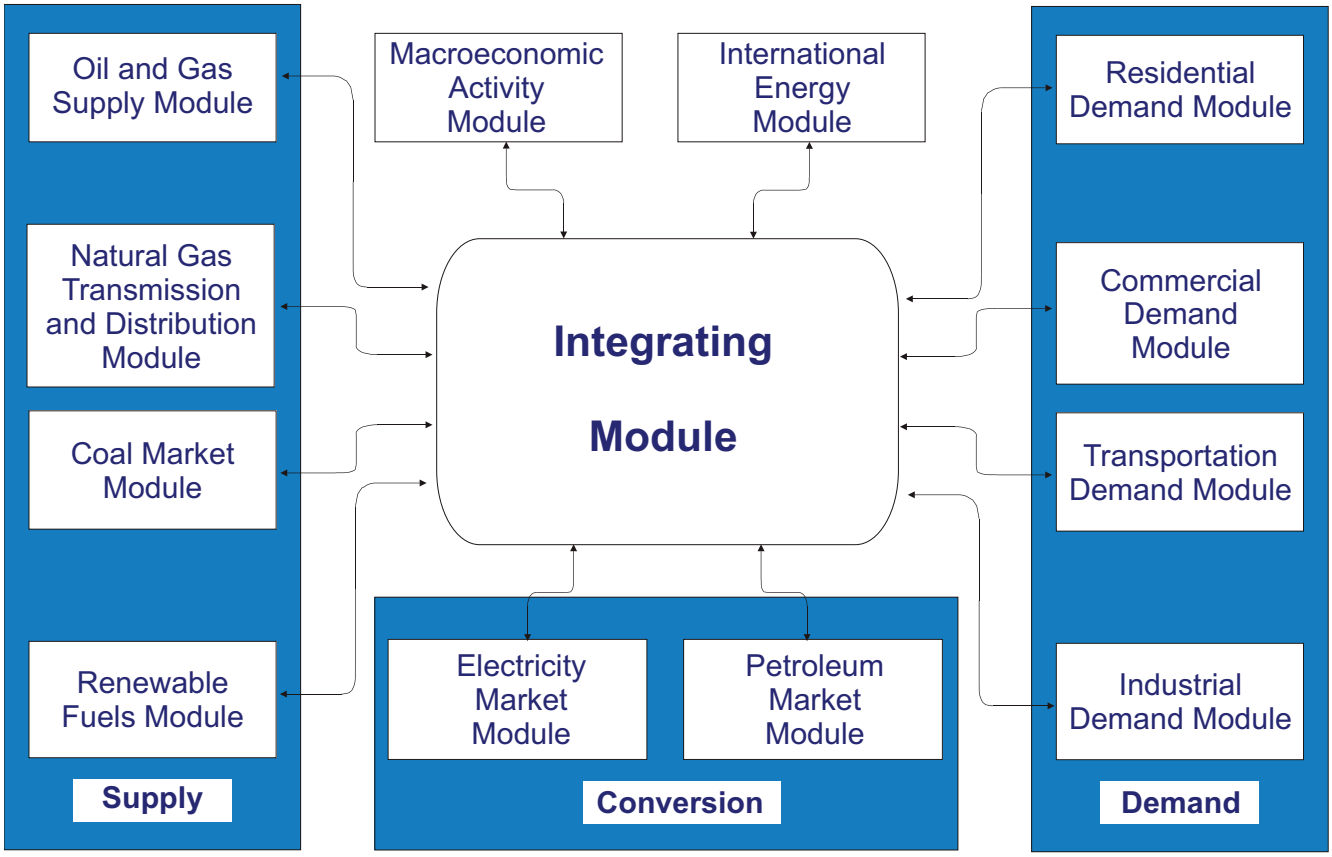
Division 6
East South Central
Alabama
Kentucky
Mississippi
Tennessee

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

Figure 2. National Energy Modeling System



Integrating Module

The NEMS integrating module controls the entire NEMS solution process as it iterates to determine a general market equilibrium across all the NEMS modules. It has the following functions:

- Manages the NEMS global data structure
- Executes all or any of the user-selected modules in an iterative convergence algorithm
- Checks for convergence and reports variables that remain out of convergence
- Implements convergence relaxation on selected variables between iterations to accelerate convergence
- Updates expected values of the key NEMS variables.

The integrating module executes the demand, conversion, and supply modules iteratively until it achieves an economic equilibrium of supply and demand in all the consuming and producing sectors. Each module is called in sequence and solved, assuming that all other variables in the energy markets are fixed. The modules are called iteratively until the end-use prices and quantities remain constant within a specified tolerance, a condition defined as convergence. Equilibration is achieved annually throughout the projection period, currently through 2030, for each of the nine Census divisions.

In addition, the macroeconomic activity and international energy modules are executed iteratively to incorporate the feedback on the economy and international energy markets from changes in the domestic energy markets. Convergence tests check the stability of a set of key macroeconomic and international trade variables in response to interactions with the domestic energy system.

The NEMS algorithm executes the system of modules until convergence is reached. The solution procedure for one iteration involves the execution of all the component modules, as well as the updating of expectation variables (related to foresight assumptions) for use in the next iteration. The system is executed sequentially for

each year in the projection period. During each iteration, the modules are executed in turn, with intervening convergence checks that isolate specific modules that are not converging. A convergence check is made for each price and quantity variable to see whether the percentage change in the variable is within the assumed tolerance. To avoid unnecessary iterations for changes in insignificant values, the quantity convergence check is omitted for quantities less than a user-specified minimum level. The order of execution of the modules may affect the rate of convergence but will generally not prevent convergence to an equilibrium solution or significantly alter the results. An optional relaxation routine can be executed to dampen swings in solution values between iterations. With this option, the current iteration values are reset partway between solution values from the current and previous iterations. Because of the modular structure of NEMS and the iterative solution algorithm, any single module or subset of modules can be executed independently. Modules not executed are bypassed in the calling sequence, and the values they would calculate and provide to the other modules are held fixed at the values in the global data structure, which are the solution values from a previous run of NEMS. This flexibility is an aid to independent development, debugging, and analysis.

Carbon Dioxide Emissions

Carbon Dioxide Emissions

The emissions policy submodule, part of the integrating module, estimates energy-related carbon dioxide emissions and is capable of representing two related greenhouse gas (GHG) emissions policies: a cap-and-trade program and a carbon dioxide emission tax.

Carbon dioxide emissions are calculated from fossil-fuel energy consumption and fuel-specific emissions factors. The estimates are adjusted for carbon capture technologies where applicable. Carbon dioxide emissions from energy use are dependent on the carbon content of the fossil fuel, the fraction of the fuel consumed in combustion, and the consumption of that fuel. The product of the carbon content at full combustion and the combustion fraction yields an adjusted carbon emission factor. The adjusted carbon emissions factors, one for each fuel and sector, are provided as input to the emissions policy module.

Data on past carbon dioxide emissions and emissions factors are updated each year from the EIA's annual inventory, *Emissions of Greenhouse Gases the United States*.[10] To provide a more complete accounting of greenhouse gas emissions consistent with that inventory, a baseline emissions projection for the non-energy carbon dioxide and other greenhouse gases may be specified as an exogenous input.

To represent carbon tax or cap-and-trade policies, an incremental cost of using each fossil fuel, on a dollar-per-Btu basis, is calculated based the carbon dioxide emissions factors and the per-ton carbon dioxide tax or cap-and-trade allowance cost. This incremental cost, or carbon price adjustment, is added to the corresponding energy prices as seen by the energy demand modules. These price adjustments influence energy demand and energy-related CO_2 emissions, as well as macroeconomic trends.

Under a cap-and-trade policy, the allowance or permit price is determined in an iterative solution process such that the annual covered emissions match the cap each year. If allowance banking is permitted, a constant-growth allowance price path is found such that cumulative emissions over the banking interval match the cumulative covered emissions. To the extent the policies cover greenhouse gases other than CO_2, the coverage assumptions and abatement potential for the gases must be provided as input. In past studies, EIA has drawn on work by the Environmental Protection Agency (EPA) to represent exogenous estimates of emissions abatement and the use of offsets as a function of allowance prices.

Representing specific cap-and-trade policies in NEMS almost always requires customization of the model. Among the issues that must be addressed are what gases and sectors are covered, what offsets are eligible as compliance measures, how the revenues raised by the taxes or allowance sales are used, how allowances or the value of allowances are distributed, and how the distribution affects energy pricing or the cost of using energy.

10 Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2007*, DOE/EIA-0573 (2007) (Washington, DC, December 2008), web site www.eia.doe.gov/oiaf/1605/ggrpt/index.html.

Macroeconomic Activity Module

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) links NEMS to the rest of the economy by providing projections of economic driver variables for use by the supply, demand, and conversion modules of NEMS. The derivation of the baseline macroeconomic projection lays a foundation for the determination of the energy demand and supply forecast. MAM is used to present alternative macroeconomic growth cases to provide a range of uncertainty about the growth potential for the economy and its likely consequences for the energy system. MAM is also able to address the macroeconomic impacts associated with changing energy market conditions, such as alternative world oil price assumptions. Outside of the *AEO* setting, MAM represents a system of linked modules which can assess the potential impacts on the economy of changes in energy events or policy proposals. These economic impacts then feed back into NEMS for an integrated solution. MAM consists of five submodules:

- Global Insight Model of the U.S. Economy
- Global Insight Industry Model
- Global Insight Employment Model
- EIA Regional Model
- EIA Commercial Floorspace Model

The IHS Global Insight Model of the U.S. Economy (Macroeconomic Model) is the same model used by IHS Global Insight, Inc. to generate the economic projections behind the company's monthly assessment of the U.S. economy. The Industry and Employment submodules, are derivatives of IHS Global Insight's Industry and Employment Models, and have been tailored to provide the industry and regional detail required by NEMS. The Regional and Commercial Floorspace Submodules were developed by EIA to complement the set of Global Insight models, providing a fully integrated approach to projecting economic activity at the national, industry and regional levels. The set of models is designed to run in a recursive manner (see Figure 3). Global Insight's Macroeconomic Model determines the national economy's growth path and final demand mix. The Global Insight Macroeconomic Model provides projections of over 1300 concepts spanning final demands, aggregate supply, prices, incomes, international trade, industrial detail, interest rates and financial flows.

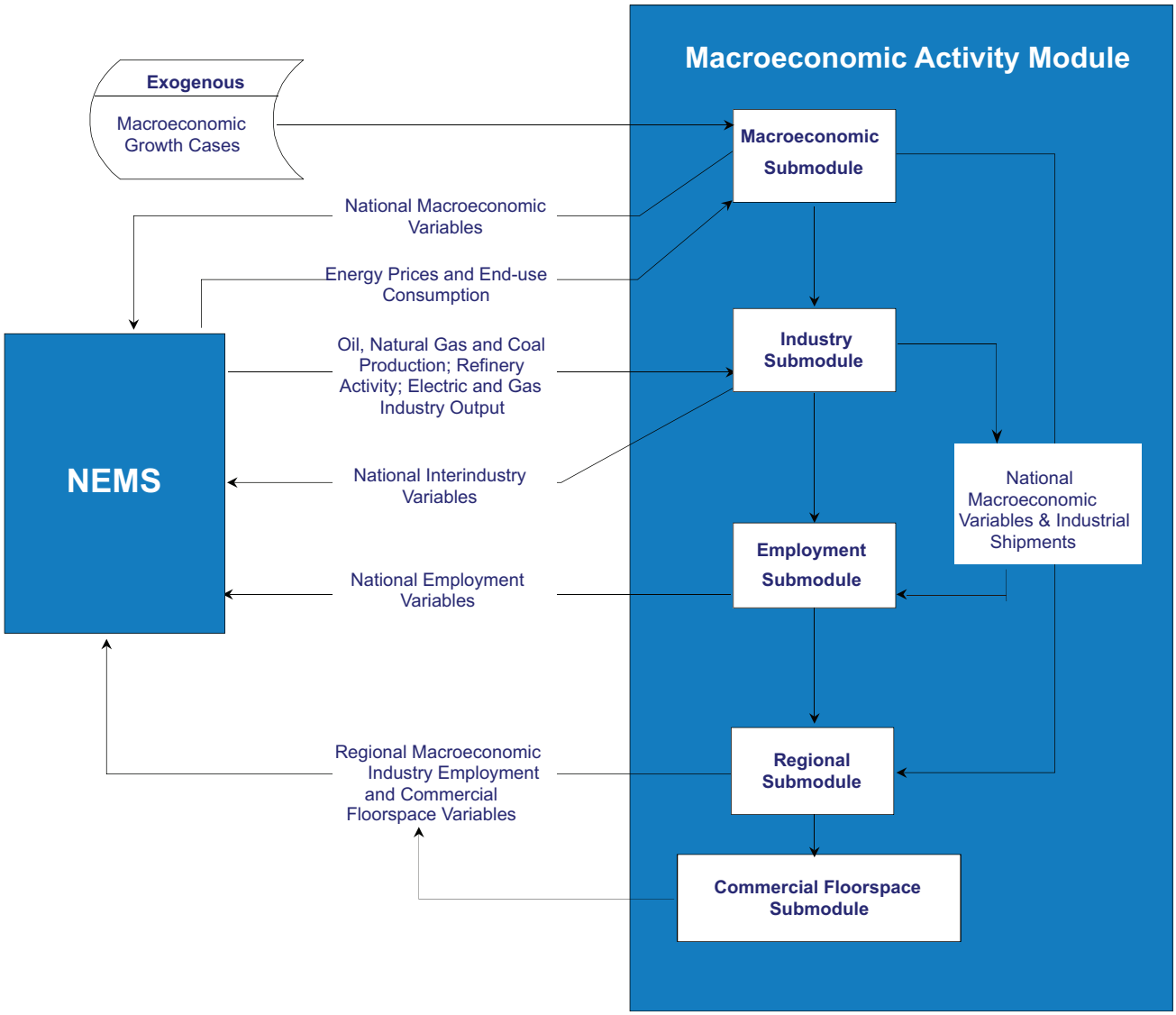
The Industry Submodule takes the final demand projections from the Macroeconomic Submodule as inputs to provide projections of output and other key indicators for 61 sectors, covering the entire economy. This is later aggregated to 41 sectors to provide information to NEMS. The Industry Submodule insures that supply by industry is consistent with the final demands (consumption, investment, government spending, exports and imports) generated in the Macroeconomic Submodule.

The Employment Submodule takes the industry output projections from the Industry Submodule and national wage rates, productivity trends and average work-week trends from the Macroeconomic Submodule to project employment for the 41 NEMS industries. The sum of non-agricultural employment is constrained to sum to the national total projected by the Macroeconomic Submodule.

The Regional Submodule determines the level of industry output and employment, population, incomes, and housing activity in each of nine Census regions. The Commercial Floorspace Submodule calculates regional floorspace for 13 types of building use by Census Division.

MAM Outputs	Inputs from NEMS	Exogenous Inputs
Gross domestic product Other economic activity measures, including housing starts, commercial floorspace growth, vehicle sales, population Price indices and deflators Production and employment for manufacturing Production and employment for nonmanufacturing Interest rates	Petroleum, natural gas, coal, and electricity prices Oil, natural gas, and coal production Electric and gas industry output Refinery output End-use energy consumption by fuel	Macroeconomic variables defining alternative economic growth cases

Figure 3. Macroeconomic Activity Module Structure



Integrated forecasts of NEMS center around estimating the state of the energy-economy system under a set of alternative energy conditions. Typically, the projections fall into the following four types of integrated NEMS simulations:

- Baseline Projection
- Alternative World Oil Prices
- Proposed Energy Fees or Emissions Permits
- Proposed Changes in Combined Average Fuel Economy (CAFE) Standards

In these integrated NEMS simulations, projection period baseline values for over 240 macroeconomic and demographic variables from MAM are passed to NEMS which solves for demand, supply and prices of energy for the projection period. These energy prices and quantities are passed back to MAM and solved in the Macroeconomic, Industry, Employment, Regional, and Commercial Floorspace Submodules in the EViews environment.[11]

11 Eviews is a model building nad operating software package maintained by QMS (Quantitative Micro Software.)

International Energy Module

International Energy Module

The International Energy Module (IEM) (Figure 4) performs the following functions:

- Calculates the world oil price (WOP) that equilibrates world crude-like liquids supply with demand for each year. The WOP is defined as the price of light, low sulfur crude oil delivered to Cushing, Oklahoma.
- Provides the projected world crude-like liquids supply curve (for each year) used by the Petroleum Market Module (PMM). These curves are adjusted to reflect expected conditions in international oil markets and projected changes in U.S. crude-like liquids production and consumption.
- Provide annual regional (country) level production detail for conventional and unconventional liquids based on exogenous assumptions about expected country-level liquid fuels production and producer behavior.
- Projects crude oil and light and heavy refined product import quantities into the U.S. by year and by source based on exogenous assumptions about future exploration, production, refining, and distribution investments worldwide.

Scope of IEM

Non-U.S. liquid fuels markets are represented in NEMS by the interaction between the PMM and the IEM. Using the specific algorithm described in the documentation of this module, IEM calculates the WOP that equilibrates world crude-like liquids supply with demand for each year. The IEM then estimates new world crude-like liquids supply curves based on exogenous, expected U.S. and world crude-like liquids supply and demand curves and that incorporate any changes in U.S. crude-like liquids production or consumption projected by other NEMS modules. Operationally, IEM passes to PMM an array of nine points of this supply curve, with the equilibrium point being the fifth point of this array.

Input data into IEM contain the historical percentages of imports of oils, heavy and light products imported into U.S. from different regions in the world. Using these values and total imports into the U.S. of crudes, heavy and light products provided by PMM, IEM generates a report, with imports by source for every year in the projection.

While the IEM is intended to be executed as a module of the NEMS system, and utilizing its complete capabilities and features requires a NEMS interface, it is also possible to execute the IEM module on a stand-alone basis. In stand-alone mode, the IEM calculates the WOP based on an exogenously specified projection of U.S. crude-like liquids production and consumption. Sensitivity analyses can be conducted to examine the response of the world oil market to changes in oil price, production capacity, and demand. To summarize, the model searches for the WOP that equilibrates crude-like liquids supply and demand at the world level.

Based on the final results for U.S. total liquids production and consumption, IEM also provides an International Petroleum Supply and Disposition Summary table for world conventional and unconventional liquids production as well as for world liquids demand by region. Exogenous data used to build this report is contained in omsinput.wk1 file. Each scenario has its own version of this file.

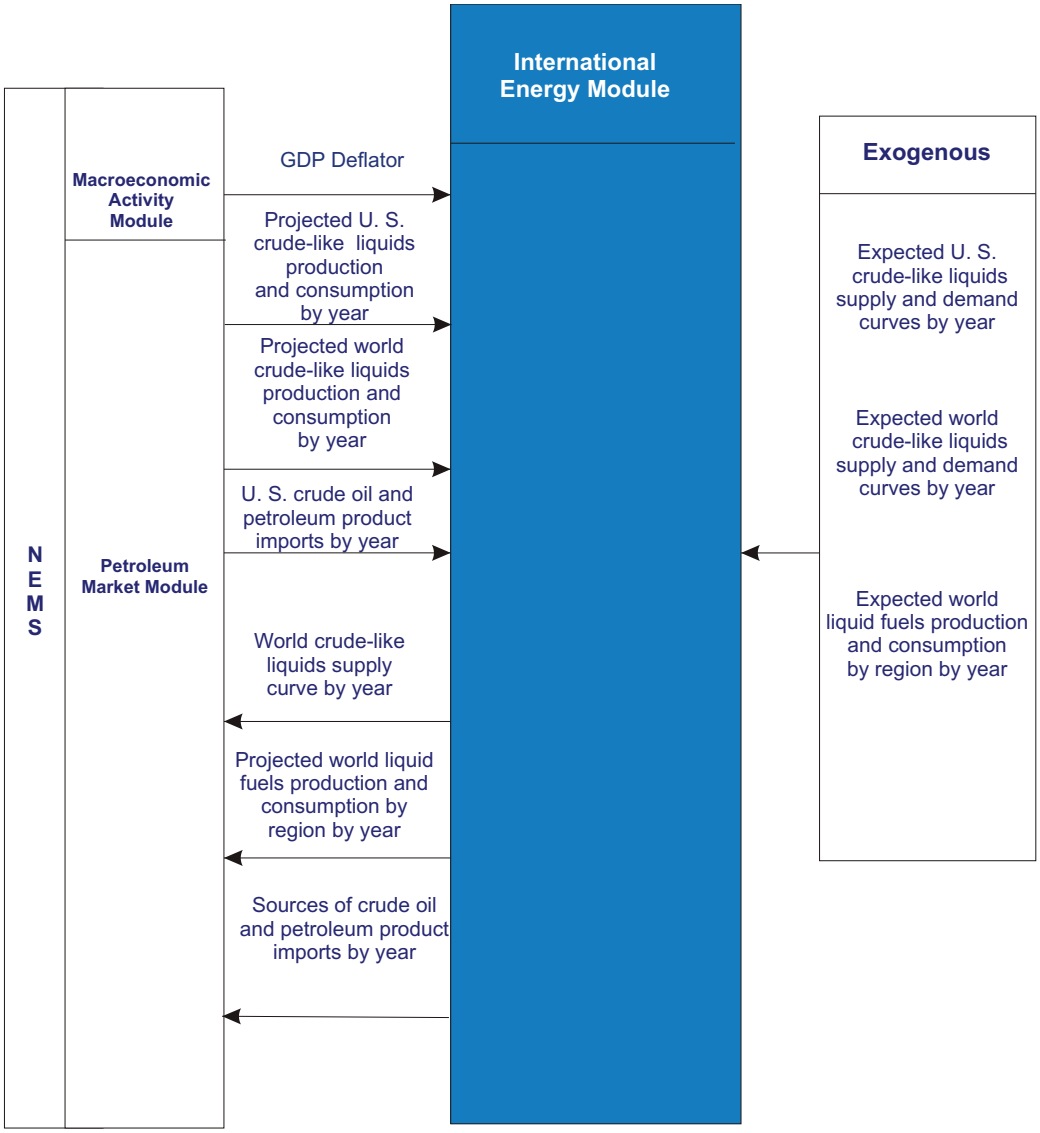
Because U.S. production and consumption of conventional liquids are dynamic values (output from NEMS), all other world regions have been proportionally updated such that the world liquids production and consumption reflect the corresponding value as in the *International Energy Outlook* (*IEO*).

Relation to Other NEMS Components

The IEM both uses information from and provides information to other NEMS components. It primarily uses information about projected U.S and world crude-like liquids production and consumption and petroleum imports and provides information about the world liquid fuels markets, including global crude-like liquids supply curves and the sources of petroleum imports into the U.S. It should be noted, however, that the present focus of the IEM is on the international oil market where the

IEM *Outputs*	Inputs from NEMS	Exogenous Inputs
World crude-like liquids supply curves Projected world liquid fuels production and consumption by region Sources of crude oil and petroleum product imports by year	Controlling information: iteration count, time horizon, etc GDP deflator Projected U.S. and world crude-like liquids production and consumption U.S. crude oil and petroleum product imports	Expected US and world crude-like liquids supply and demand curves Expected world liquid fuel production and consumption by region

Figure 4. International Energy Module Structure



WOP is computed. Any interactions between the U.S. and foreign regions in fuels other than oil (for example, coal trade) are modeled in the particular NEMS module that deals with that fuel.

For U.S. crude-like liquids production and consumption in any year of the projection period, the IEM uses projections generated by the NEMS PMM (based on supply curves provided by the Oil and Gas Supply Module (OGSM) and demand curves from the end-use demand modules).

U.S. and world expected crude-like liquids supply and demand curves, for any year in the projection period, are exogenously provided through data included in input file omsecon.txt, as detailed in the documentation of the IEM.

Residential Demand Module

Residential Demand Module

The residential demand module (RDM) projects energy consumption by Census division for seven marketed energy sources plus solar, wind, and geothermal energy. RDM is a structural model and its demand projections are built up from projections of the residential housing stock and energy-consuming equipment. The components of RDM and its interactions with the NEMS system are shown in Figure 5. NEMS provides projections of residential energy prices, population, disposable income, and housing starts, which are used by RDM to develop projections of energy consumption by end–use service, fuel type, and Census division.

RDM incorporates the effects of four broadly-defined determinants of energy consumption: economic and demographic effects, structural effects, technology turnover and advancement effects, and energy market effects. Economic and demographic effects include the number, dwelling type (single-family, multifamily or mobile homes), occupants per household, disposable income, and location of housing units.Structural effects include increasing average dwelling size and changes in the mix of desired end-use services provided by energy (new end uses and/or increasing penetration of current end uses, such as the increasing popularity of electronic equipment and computers). Technology effects include changes in the stock of installed equipment caused by normal turnover of old, worn out equipment with newer versions that tend to be more energy efficient, the integrated effects of equipment and building shell (insulation level) in new construction, and the projected availability of even more energy-efficient equipment in the future. Energy market effects include the short-run effects of energy prices on energy demands, the longer-run effects of energy prices on the efficiency of purchased equipment and the efficiency of building shells, and limitations on minimum levels of efficiency imposed by legislated efficiency standards.

Housing Stock Submodule

The base housing stock by Census division and dwelling type is derived from EIA's 2005 Residential Energy Consumption Survey (RECS). Each element of the of the base stock is retired on the basis of a constant rate of decay for each dwellling type. RDM receives as an input from the macroeconomic activity module projections of housing additions by type and Census division. RDM supplements the surviving stocks from the previous year with the projected additions by dwelling type and Census division. The average square footage of new construction is based on recent upward trends developed from the RECS and the Census Bureau's Characteristics of New Housing.

Appliance Stock Submodule

The installed stock of appliances is also taken from the 2005 RECS. The efficiency of the appliance stock is derived from historical shipments by efficiency level over a multi-year interval for the following equipment: heat pumps, gas furnaces, central air conditioners, room air conditioners, water heaters, refrigerators, freezers, stoves, dishwashers, clothes washers, and clothes dryers. A linear retirement function with both minimum and maximum equipment lives is used to retire equipment in surviving housing units. For equipment where shipment data are available, the efficiency of the retiring equipment varies over the projection. In early years, the retiring efficiency tends to be lower as the older, less efficient equipment in the stock turns over first. Also, as housing units retire, the associated appliances are removed from the base appliance stock as well. Additions to the base stock are tracked separately for housing units existing in 2005 and for cumulative new construction.

As appliances are removed from the stock, they are replaced by new appliances with generally higher efficiencies due to technology improvements, equipment standards, and market forces. Appliances added due to new construction are accumulated and retired parallel to appliances in the existing stock. Appliance stocks are maintained by fuel, end use, and technology as shown in Table 2.

Technology Choice Submodule

Fuel-specific equipment choices are made for both new construction and replacement purchases. For new construction, initial heating system shares (taken from the most recently available Census Bureau survey data covering new construction, currently 2005) are adjusted

RDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy demand by service and fuel type Changes in housing and appliance stocks Appliance stock efficiency	Energy product prices Housing starts Population	Current housing stocks and retirement rates Current appliance stocks and life expectancy New appliance types, efficiences, and costs Housing shell retrofit indices Unit energy consumption Square footage

Figure 5. Residential Demand Module Structure

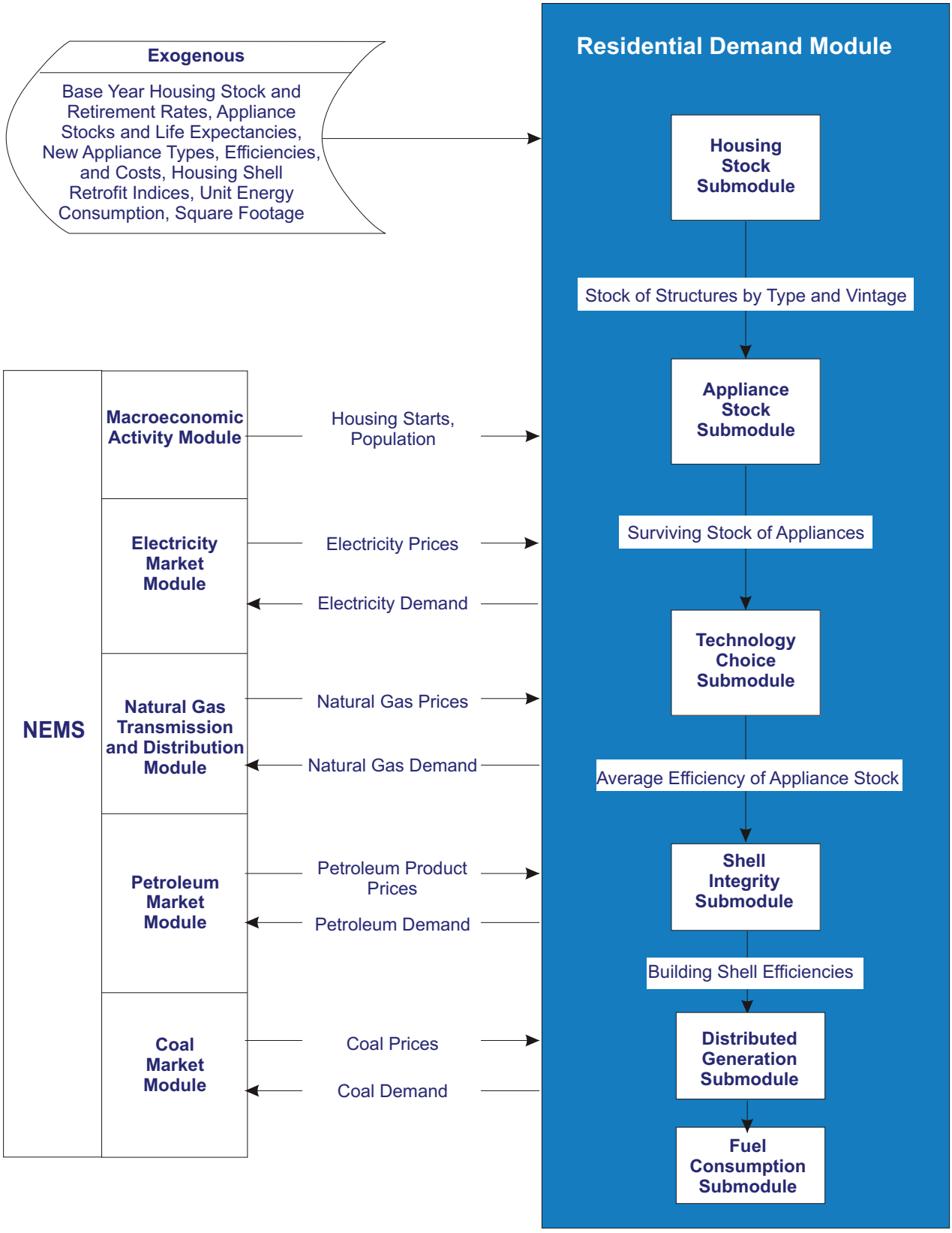


Table 2. NEMS Residential Module Equipment Summary

Space Heating Equipment: electric furnace, electric air-source heat pump, natural gas furnace, natural gas hydronic, kerosene furnace, liquefied petroleum gas, distillate furnace, distillate hydronic, wood stove, ground-source heat pump, natural gas heat pump.
Space Cooling Equipment: room air conditioner, central air conditioner, electric air-source heat pump, ground-source heat pump, natural gas heat pump.
Water Heaters: solar, natural gas, electric distiallate, liquefied petroleum gas.
Refrigerators: 18 cubic foot top-mounted freezer, 25 cubic foot side-by-side with through-the-door features.
Freezers: chest - manual defrost, upright - manual defrost.
Lighting: incandescent, compact fluorescent, LED, halogen, linear fluoresent.
Clothes Dryers: natural gas, electric.
Cooking: natural gas, electric, liquefied petroleum gas.
Dishwashers
Clothes Washers
Fuel Cells
Solar Photovoltaic
Wind

based on relative life cycle costs for all competing technology and fuel combinations. Once new home heating system shares are established, the fuel choices for other services, such as water heating and cooking, are determined based on the fuel chosen for space heating. For replacement purchases, fuel switching is allowed for an assumed percentage of all replacements but is dependent on the estimated costs of fuel-switching (for example, switching from electric to gas heating is assumed to involve the costs of running a new gas line).

For both replacement equipment and new construction, a "second-stage" of the equipment choice decision requires selecting from several available efficiency levels. The efficiency range of available equipment represents a "menu" of efficiency levels and installed cost combinations projected to be available at the time the choice is being made. Costs and efficiencies for selected appliances are shown in Table 3, derived from the report Assumptions to the *Annual Energy Outlook 2009*.[12] At the low end of the efficiency range are the minimum levels required by legislated standards. In any given year, higher efficiency levels are associated with higher installed costs. Thus, purchasing higher than the minimum efficiency involves a trade-off between higher installation costs and future savings in energy expenditures. In RDM, these trade-offs are calibrated to recent shipment, cost, and efficiency data. Changes in purchases by efficiency level are based on changes in either the installed capital costs or changes in the first-year operating costs across the available efficiency levels. As energy prices increase, the incentive of greater energy expenditures savings will promote increased purchases of higher-efficiency equipment. In some cases, due to government programs or general projections of technology improvement, increases in efficiency or decreases in the installed costs of higher-efficiency equipment will also promote purchases of higher-efficiency equipment.

Shell Integrity Submodule

Shell integrity is also tracked separately for the existing housing stock and new construction. Shell integrity for existing construction is assumed to respond to increases in real energy prices by becoming more efficient. There is no change in existing shell integrity when real energy prices decline. New shell efficiencies are based on the cost and performance of the heating and cooling equipment as well as the shell characteristics. Several efficiency levels of shell characteristics are available throughout the projection period and can change over time based on changes in building codes. All shell efficiencies are subject to a maximum shell efficiency based on studies of currently available residential construction methods.

Distributed Generation Submodule

Distributed generation equipment with explicit technology characterizations is also modeled for residential customers. Currently, three technologies are characterized, photovoltaics, wind, and fuel cells. The submodule incorporates historical estimates of photovoltaics (residential-sized fuel cells are not expected to be commercialized until after 2005, the base year of the model) from its technology characterization and exogenous penetration input file. Program-based photovoltaic

12 Energy Information Administration, Assumptions to the Annual Energy Outlook 2009, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2009).pdf (Washington, DC, March 2009).

estimates for the Department of Energy's Million Solar Roofs program are also input to the submodule from the exogenous penetration portion of the input file. Endogenous, economic purchases are based on a penetration function driven by a cash flow model that simulates the costs and benefits of distributed generation purchases. The cash flow calculations are developed from NEMS projected energy prices coupled with the technology characterizations provided from the input file.

Potential economic purchases are modeled by Census division and technology for all years subsequent to the base year. The cash flow model develops a 30-year cost-benefit horizon for each potential investment. It includes considerations of annual costs (down payments, loan payments, maintenance costs and, for fuel cells, gas costs) and annual benefits (interest tax deductions, any applicable tax credits, electricity cost savings, and water heating savings for fuel cells) over the entire 30-year period. Penetration for a potential investment in either photovoltaics, wind, or fuel cells is a function of whether it achieves a cumulative positive discounted cash flow, and if so, how many years it takes to achieve it.

Once the cumulative stock of distributed equipment is projected, reduced residential purchases of electricity are provided to NEMS. For fuel cells, increased residential natural gas consumption is also provided to NEMS based on the calculated energy input requirements of the fuel cells, partially offset by natural gas water heating savings from the use of waste heat from the fuel cell.

Energy Consumption Submodule

The fuel consumption submodule modifies base year energy consumption intensities in each projection year. Base year energy consumption for each end use is derived from energy intensity estimates from the 2005 RECS. The base year energy intensities are modified for the following effects: (1) increases in efficiency, based on a comparison of the appliance stock serving this end use relative to the base year stock, (2) changes in shell integrity for space heating and cooling end uses, (3) changes in real fuel prices—(short-run price elasticity effects), (4) changes in square footage, (5) changes in the number of occupants per household, (6) changes in disposable income, (7) changes in weather relative to the base year, (8) adjustments in utilization rates caused by efficiency increases (efficiency "rebound" effects), and (9) reductions in purchased electricity and increases in natural gas consumption from distributed generation. Once these modifications are made, total energy use is computed across end uses and housing types and then summed by fuel for each Census division.

Table 3. Characteristics of Selected Equipment

Equipment Type	Relative Performance[1]	2007 Installed Cost ($2007)[2]	Efficiency[3]	2020 Installed Cost ($2007)[2]	Efficiency[3]	Approximate Hurdle Rate
Electric Heat Pump	Minimum	$3,800	13.0	$3,800	13.0	15%
	Best	$6,700	17.0	$6,700	20.0	
Natural Gas Furnace	Minimum	$1,900	0.80	$1,900	0.80	15%
	Best	$3,050	0.96	$2,700	0.96	
Room Air Conditioner	Minimum	$310	9.8	$310	9.8	140%
	Best	$925	11.7	$875	12.0	
Central Air Conditioner	Minimum	$3,000	13.0	$3,000	13.0	15%
	Best	$5,700	21.0	$5,750	23.0	
Refrigerator (23.9 cubic ft in adjusted volume)	Minimum	$550	510	$550	510	19%
	Best	$950	417	$1000	417	
Electric Water Heater						
	Minimum	$400	0.90	$400	0.90	30%
	Best	$1,400	2.4	$1,700	2.4	

[1]Minimum performance refers to the lowest efficiency equipment available. Best refers to the highest efficiency equipment available.

[2]Installed costs are given in 2007 dollars in the original source document.

[3]Efficiency measurements vary by equipment type. Electric heat pumps and central air conditioners are rated for cooling performance using the Seasonal Energy Efficiency Ratio (SEER); natural gas furnaces are based on Annual Fuel Utilization Efficiency; room air conditioners are based on Energy Efficiency Ratio (EER); refrigerators are based on kilowatt-hours per year; and water heaters are based on Energy Factor (delivered Btu divided by input Btu).

Source: Navigant Consulting, *EIA Technology Forecast Updates-Residential and Commercial Buildings Technologies*, September 2007.

Commercial Demand Module

Commercial Demand Module

The commercial demand module (CDM) projects energy consumption by Census division for eight marketed energy sources plus solar, wind, and geothermal energy. For the three major commercial sector fuels, electricity, natural gas and distillate oil, CDM is a structural model and the projections are built up from the stock of commercial floorspace and energy-consuming equipment. For the remaining five marketed minor fuels, simple econometric projections are made.

The commercial sector encompasses business establishments that are not engaged in industrial or transportation activities. Commercial sector energy is consumed mainly in buildings, except for a relatively small amount for services such as street lights and water supply. CDM incorporates the effects of four broadly-defined determinants of energy consumption: economic and demographics, structural, technology turnover and change, and energy markets. Demographic effects include total floorspace, building type and location. Structural effects include changes in the mix of desired end-use services provided by energy (such as the penetration of telecommunications equipment, personal computers and other office equipment). Technology effects include changes in the stock of installed equipment caused by the normal turnover of old, worn out equipment to newer versions that tend to be more energy efficient, the integrated effects of equipment and building shell (insulation level) in new construction, and the projected availability of equipment with even greater energy-efficiency. Energy market effects include the short-run effects of energy prices on energy demands, the longer-run effects of energy prices on the efficiency of purchased equipment, and limitations on minimum levels of efficiency imposed by legislated efficiency standards. The model structure carries out a sequence of five basic steps, as shown in Figure 6. The first step is to project commercial sector floorspace. The second step is to project the energy services (space heating, lighting, etc.) required by the projected floorspace. The third step is to project the electricity generation and water and space heating supplied by distributed generation and combined heat and power (CHP) technologies. The fourth step is to select specific technologies (natural gas furnaces, fluorescent lights, etc.) to meet the demand for energy services. The last step is to determine how much energy will be consumed by the equipment chosen to meet the demand for energy services.

Floorspace Submodule

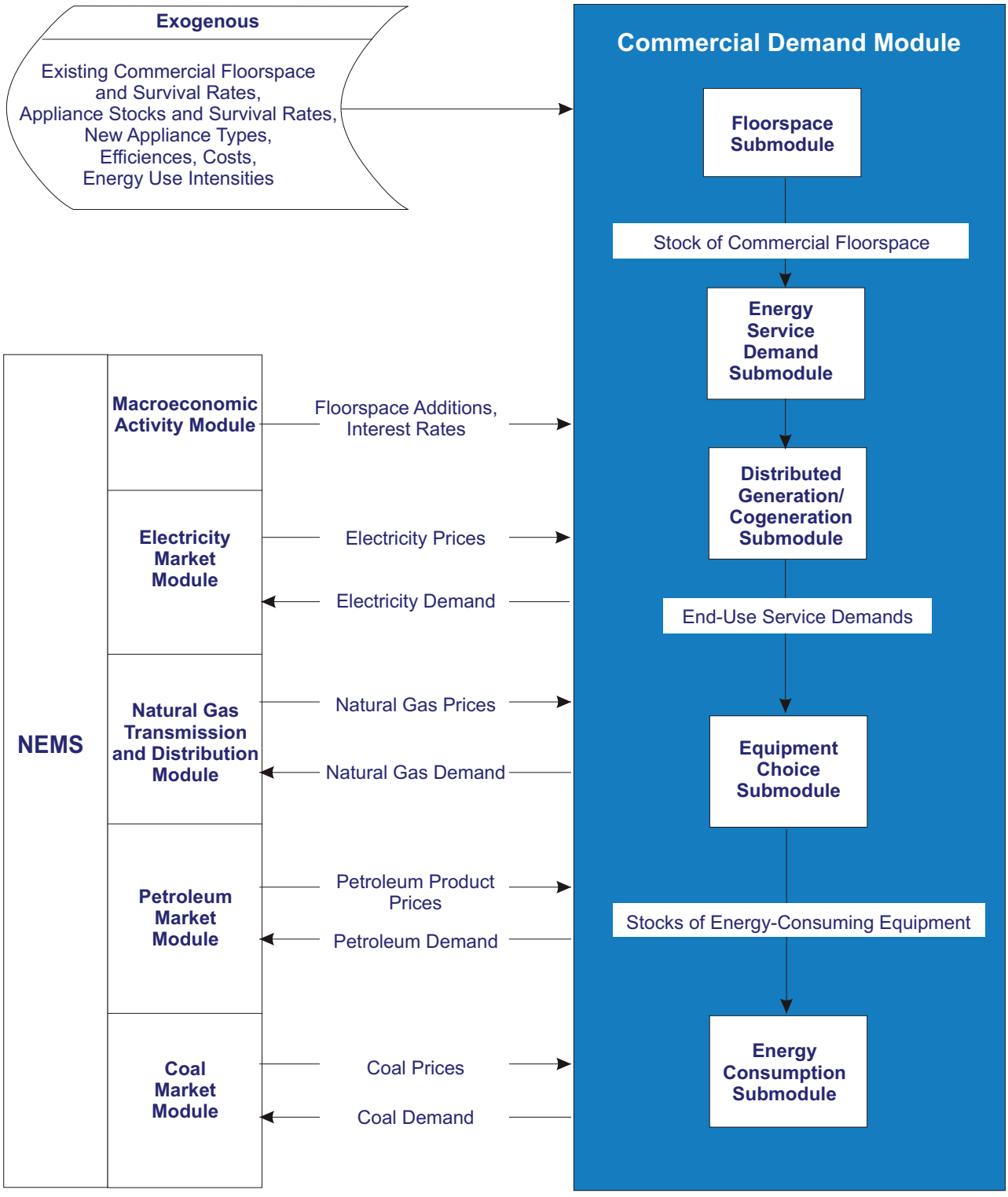
The base stock of commercial floorspace by Census division and building type is derived from EIA's 2003 Commercial Buildings Energy Consumption Survey (CBECS). CDM receives projections of total floorspace by building type and Census division from the macroeconomic activity module (MAM) based on IHS Global Insight, Inc. definitions of the commercial sector. These projections embody both economic and demographic effects on commercial floorspace. Since the definition of commercial floorspace from IHS Global Insight, Inc. is not calibrated to CBECS, CDM estimates the surviving floorspace from the previous year and then calibrates its new construction so that growth in total floorspace matches that from MAM by building type and Census division.

CDM models commercial floorspace for the following 11 building types:

- Assembly
- Education
- Food sales
- Food service
- Health care
- Lodging
- Office-large
- Office-small
- Mercantile and service
- Warehouse
- Other

CDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy demand by service and fuel type Changes in floorspace and appliance stocks	Energy product prices Interest rates Floorspace growth	Existing commercial floorspace Floorspace survival rates Appliance stocks and survival New appliance types, efficiencies, costs Energy use intensities

Figure 6. Commercial Demand Module Structure



Commercial Demand Module

Energy Service Demand Submodule

Energy consumption is derived from the demand for energy services. So the next step is to project energy service demands for the projected floorspace. CDM models service demands for the following ten end-use services:

- Heating
- Cooling
- Ventilation
- Water heating
- Lighting
- Cooking
- Refrigeration
- Office equipment personal computer
- Office equipment other
- Other end uses.

Different building types require unique combinations of energy services. A hospital must have more light than a warehouse. An office building in the Northeast requires more heating than one in the South. Total service demand for any service depends on the floorspace, type, and location of buildings. Base service demand by end use by building type and Census division is derived from estimates developed from CBECS energy consumption data. Projected service demands are adjusted for trends in new construction based on CBECS data concerning recent construction.

Distributed Generation and CHP Submodule

Commercial consumers may decide to purchase equipment to generate electricity (and perhaps provide heat as well) rather than depend on purchased electricity to fulfill all of their electric power requirements. The third step of the commercial module structure is to project electricity generation, fuel consumption, water heating, and space heating supplied by eleven distributed generation and CHP technologies. The technologies characterized include: photovoltaic solar systems, wind turbines, natural gas fuel cells, reciprocating engines, turbines and microturbines, diesel engine, coal-fired CHP, and municipal solid waste, wood, and hydroelectric generators.

Existing electricity generation by CHP technologies is derived from historical data contained in the most recent year's version of Form EIA-860, Annual Electric Generator Report. The estimated units form the installed base of CHP equipment that is carried forward into future years and supplemented with any additions. Proven installations of solar photovoltaic systems, wind turbines and fuel cells are also included based on information from the Departments of Energy and Defense. For years following the base year, an endogenous projection of distributed generation and CHP is developed based on the economic returns projected for distributed generation technologies. A detailed discounted cash-flow approach is used to estimate the internal rate of return for an investment. The calculations include the annual costs (down payments, loan payments, maintenance costs, and fuel costs) and returns (tax deductions, tax credits, and energy cost savings) from the investment covering a 30-year period from the time of the investment decision. Penetration of these technologies is a function of how quickly an investment in a technology is estimated to recoup its flow of costs. In terms of NEMS projections, investments in distributed generation reduce purchases of electricity. Fuel consuming technologies also generate waste heat that is assumed to be partially captured and used to offset commercial water heating and space heating energy use.

Equipment Choice Submodule

Once service demands are projected, the next step is to define the type and efficiency of equipment that will be used to satisfy the demands. The bulk of equipment required to meet service demand will carry over from the equipment stock of the previous model year. However, equipment must always be purchased to satisfy service demand for new construction. It must also be purchased to replace equipment that has either worn out (replacement equipment) or reached the end of its economically useful life (retrofit equipment). For required equipment replacements, CDM uses a constant decay rate based on equipment life. A technology will be retrofitted only if the combined annual operating and maintenance costs plus annualized capital costs of a potential technology are lower than the annual operating and maintenance costs of an existing technology.

Equipment choices are made based on a comparison of annualized capital and operating and maintenance costs across all allowable equipment for a particular end-use service. In order to add inertia to the equipment choices, only subsets of the total menu of potentially available equipment may be allowed for defined market segments. For example, only 7 percent of floorspace in large office buildings may consider all available equipment using any fuel or technology when making space

heating equipment replacement decisions. A second segment equal to 31 percent of floorspace, must select from technologies using the same fuel as already installed. A third segment, the remaining 62 percent of floorspace, is constrained to consider only different efficiency levels of the same fuel and technology already installed. For lighting and refrigeration, all replacement choices are limited to the same technology class, where technologies are broadly defined to encompass the principal competing technologies for a particular application. For example, a commercial ice maker may replace another ice maker, but may not replace a refrigerated vending machine.

When computing annualized costs to determine equipment choices, commercial floorspace is segmented by what are referred to as hurdle rates or implicit discount rates (to distinguish them from the generally lower and more common notion of financial discount rates). Seven segments are used to simulate consumer behavior when purchasing commercial equipment. The segments range from rates as low as the 10-year Treasury bond rate to rates high enough to guarantee that only equipment with the lowest capital cost (and least efficiency) is chosen. As real energy prices increase (decrease) there is an incentive for all but the highest implicit discount rate segments to purchase increased (decreased) levels of efficiency.

The equipment choice submodule is designed to choose among a discrete set of technologies that are characterized by a menu which defines availability, capital costs, maintenance costs, efficiencies, and equipment life. Technology characteristics for selected space heating equipment are shown Table 4, derived from the report *Assumptions to the Annual Energy Outlook 2009*.[13] This menu of equipment includes technological innovation, market developments, and policy interventions. For the *AEO2009*, the technology types that are included for seven of the ten service demand categories are listed in Table 5.

The remaining three end-use services (PC-related office equipment, other office equipment, and other end uses) are considered minor services and are projected using exogenous equipment efficiency and market penetration trends.

Energy Consumption Submodule

Once the required equipment choices have been made, the total stock and efficiency of equipment for a particular end use are determined. Energy consumption by fuel can be calculated from the amount of service demand satisfied by each technology and the corresponding efficiency of the technology. At this stage, adjustments to energy consumption are also made. These include adjustments for changes in real energy prices (short-run price elasticity effects), adjustments in utilization rates caused by efficiency increases (efficiency rebound effects), and changes for weather relative to the CBECS survey year. Once these modifications are made, total energy use is computed across end uses and building types for the three major fuels, for each Census division. Combining these projections with the econometric/trend projections for the five minor fuels yields total projected commercial energy consumption.

13 Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2009).pdf (Washington, DC, March 2009)

Table 4. Capital Cost and Efficiency Ratings of Selected Commercial Space Heating Equipment[1]

Equipment Type	Vintage	Efficiency[2]	Capital Cost ($2007 per Mbtu/hour) [3]	Maintenance Cost ($2007 per Mbtu/hour) [3]	Service Life (Years)
Electric Rooftop Heat Pump	2007- typical	3.2	$72.78	$1.39	15
	2007- high efficiency	3.4	$96.67	$1.39	15
	2010 - typical (standard)	3.3	$76.67	$1.39	15
	2010 - high efficiency	3.4	$96.67	$1.39	15
	2020 - typical	3.3	$76.67	$1.39	15
	2020 - high efficiency	3.4	$96.67	$1.39	15
Ground-Source Heat Pump	2007 - typical	3.5	$140.00	$16.80	20
	2007 - high efficiency	4.9	$170.00	$16.80	20
	2010 - typical	3.5	$140.00	$16.80	20
	2010 - high efficiency	4.9	$170.00	$16.80	20
	2020 - typical	4.0	$140.00	$16.80	20
	2020 - high efficiency	4.9	$170.00	$16.80	20
Electric Boiler	Current typical	0.98	$17.53	$0.58	21
Packaged Electric	Typical	0.96	$16.87	$3.95	18
Natural Gas Furnace	Current Standard	0.80	$9.35	$0.97	20
	2007 - high efficiency	0.82	$9.90	$0.94	20
	2020 - typical	0.81	$9.23	$0.96	20
	2020 - high efficiency	0.90	$11.57	$0.86	20
	2030 - typical	0.82	$9.12	$0.94	20
	2030 - high efficiency	0.91	$11.44	$0.85	20
Natural Gas Boiler	Current Standard	0.80	$22.42	$0.50	25
	2007 - mid efficiency	0.85	$25.57	$0.47	25
	2007 - high efficiency	0.96	$39.96	$0.52	25
	2020 - typical	0.82	$21.84	$0.49	25
Natural Gas Heat Pump	2007 - absorption	1.4	$158.33	$2.50	15
	2010 - absorption	1.4	$158.33	$2.50	15
	2020 - absorption	1.4	$158.33	$2.50	15
Distillate Oil Furnace	Current Standard	0.81	$11.14	$0.96	20
	2020 - typical	0.81	$11.14	$0.96	20
Distillate Oil Boiler	Current Standard	0.83	$17.63	$0.15	20
	2007 - high efficiency	0.89	$19.84	$0.14	20
	2020 - typical	0.83	$17.63	$015	20

[1]Equipment listed is for the New England Census division, but is also representative of the technology data for the rest of the U.S. See the source referenced below for the complete set of technology data.·

[2]Efficiency measurements vary by equipment type. Electric rooftop air-source heat pumps, ground source and natural gas heat pumps are rated for heating performance using coefficient of performance; natural gas and distillate furnaces are based on Thermal Efficiency; and boilers are based on combustion efficiency.

[3]Capital and maintenance costs are given in 2007 dollars.

Source: Energy Information Administration, "EIA - Technology Forecast Updates - Residential and Commercial Building Technologies - Reference Case Second Edition (Revised)", Navigant Consulting, Inc., Reference Number 20070831.1, September 2007.

Table 5. Commercial End-Use Technology Types

End-Use Service by Fuel	Technology Types
Electric Space Heating	air-source heat pump, ground-source heat pump, boiler, packaged space heating
Natural Gas Space Heating	boiler, furnace, absorption heat pump
Fuel Oil Space Heating	boiler, furnace
Electric Space Cooling	air-source heat pump, ground-source heat pump, reciprocating chiller, centrifugal chiller, screw chiller, scroll chiller, rooftop air conditioner, residential style central air conditioner, window unit
Natural Gas Space Cooling	absorption chiller, engine-driven chiller, rooftop air conditioner, engine-driven heat pump, absorption heat pump
Electric Water Heating	electric resistance, heat pump water heater, solar water heater with electric back-up
Natural Gas Water Heating	natural gas water heater
Fuel Oil Water Heating	fuel oil water heater
Ventilation	constant air volume (CAV) system, variable air volume (VAV) system
Electric Cooking	range/oven/griddle, induction range/oven/griddle
Natural Gas Cooking	range/oven/griddle, power burner range/oven/griddle
Incandescent Style Lighting	incandescent, compact fluorescent, halogen, halogen-infrared, light emitting diode (LED)
Four-foot Fluorescent Lighting	magnetic ballast, electronic ballast-T8 electronic w/controls, electronic w/reflectors, electronic ballast-T5, electronic ballast-super T8, LED,
Eight-foot Fluorescent Lighting	magnetic ballast, electronic ballast, electronic-high output, LED
High Intensity-Discharge Lighting	metal halide, mercury vapor, high pressure sodium, electronic-T8 high output, electronic-T5 high output, LED
Refrigeration	supermarket compressor rack, suupermarket condenser, supermarket display case, walk-in cooler, walk-in freezer, reach-in refrigerator, reach-in freezer, ice machine, beverage merchandiser, refrigerated vending machine

Industrial Demand Module

Industrial Demand Module

The Industrial Demand Module (IDM) projects energy consumption for fuels and feedstocks for fifteen manufacturing industries and six nonmanufacturing industries, subject to delivered prices of energy and macroeconomic variables representing the value of shipments for each industry. The module includes electricity generated through Combined Heat and Power (CHP) systems that is either used in the industrial sector or sold to the electricity grid. The IDM structure is shown in Figure 7.

Industrial energy demand is projected as a combination of "bottom up" characterizations of the energy-using technology and "top down" econometric estimates of behavior. The influence of energy prices on industrial energy consumption is modeled in terms of the efficiency of use of existing capital, the efficiency of new capital acquisitions, and the mix of fuels utilized, given existing capital stocks. Energy conservation from technological change is represented over time by trend-based "technology possibility curves." These curves represent the aggregate efficiency of all new technologies that are likely to penetrate the future markets as well as the aggregate improvement in efficiency of 2002 technology.

IDM incorporates three major industry categories: energy-intensive manufacturing industries, non-energy-intensive manufacturing industries, and nonmanufacturing industries (see Table 6). The level and type of modeling and detail is different for each. Manufacturing disaggregation is at the 3-digit North American Industrial Classification System (NAICS) level, with some further disaggregation of large and energy-intensive industries. Detailed industries include food, paper, chemicals, glass, cement, steel, and aluminum. Energy product demands are calculated independently for each industry.

Each industry is modeled (where appropriate) as three interrelated components: buildings (BLD), boilers/steam/cogeneration (BSC), and process/assembly (PA) activities. Buildings are estimated to account for 4 percent of energy consumption in manufacturing industries (in nonmanufacturing industries, building energy consumption is not currently calculated).

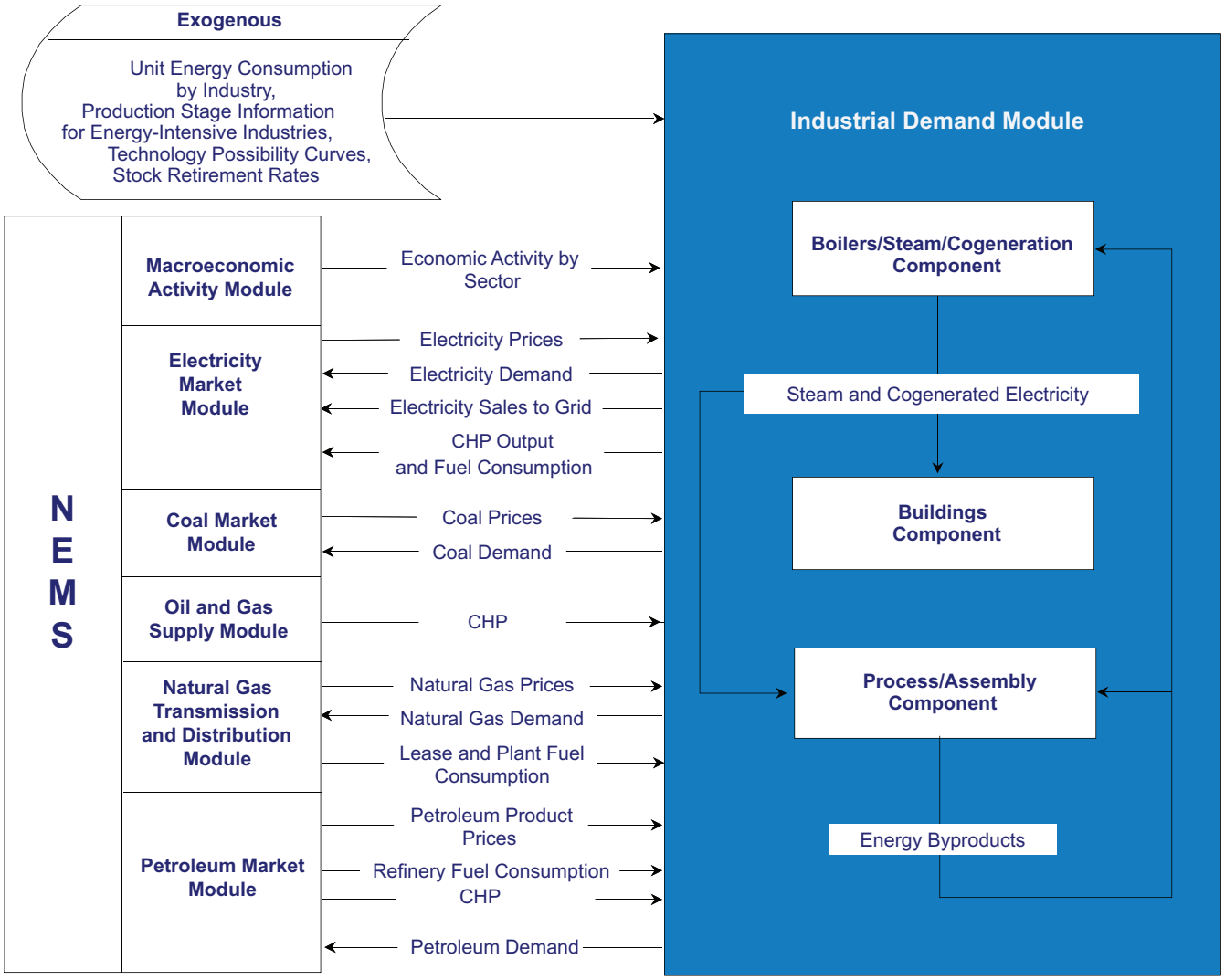
Table 6. Economic Subsectors Within the IDM

Energy-Intensive Manufacturing	**Nonmanufacturing Industries**
Food and Kindred Products (NAICS 311)	Agricultural Production - Crops (NAICS 111)
Paper and Allied Products (NAICS 322)	Other Agriculture including Livestock (NAICS 112-115)
Bulk Chemicals (NAICS 325)	Coal Mining (NAICS 2121)
Glass and Glass Products (NAICS 3272)	Oil and Gas Extraction (NAICS 211)
Hydraulic Cement (NAICS 32731)	Metal and Other Nonmetallic Mining (NAICS 2122-2123)
Blast Furnaces and Basic Steel (NAICS 331111)	Construction (NAICS 233-235)
Aluminum (NAICS 3313)	
Nonenergy-Intensive Manufacturing	
Metals-Based Durables (NAICS 332-336)	
Other Manufacturing (all remaining manufacturing NAICS)	
NAICS = North American Industry Classification System	

Consequently, IDM uses a simple modeling approach for the BLD component. Energy consumption in industrial buildings is assumed to grow at the same rate as the average growth rate of employment and output in that industry. The BSC component consumes energy to meet the steam demands from and provide internally generated electricity to the other two components. The boiler component consumes by-product fuels and fossil fuels to produce steam, which is passed to the PA and BLD components.

IDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy demand by service and fuel type Electricity sales to grid Cogeneration output and fuel consumption	Energy product prices Economic output by industry Refinery fuel consumption Lease and plant fuel consumption Cogeneration from refineries and oil and gas production	Production stages in energy-intensive industries Technology possibility curves Unit energy consumption of outputs Capital stock retirement rates

Figure 7. Industrial Demand Module Structure



IDM models "traditional" CHP based on steam demand from the BLD and the PA components. The "non-traditional" CHP units are represented in the electricity market module since these units are mainly grid-serving, electricity-price-driven entities.

CHP capacity, generation, and fuel use are calculated from exogenous data on existing and planned capacity additions and new additions determined from an engineering and economic evaluation. Existing CHP capacity and planned additions are derived from Form EIA-860, "Annual Electric Generator Report," formerly Form EIA-867, "Annual Nonutility Power Producer Report." Existing CHP capacity is assumed to remain in service throughout the projection or, equivalently, to be refurbished or replaced with similar units of equal capacity.

Calculation of unplanned CHP capacity additions begins in 2009. Modeling of unplanned capacity additions is done in two parts: biomass-fueled and fossil-fueled. Biomass CHP capacity is assumed to be added to the extent possible as additional biomass waste products are produced, primarily in the pulp and paper industry. The amount of biomass CHP capacity added is equal to the quantity of new biomass available (in Btu), divided by the total heat rate from biomass steam turbine CHP.

Table 7. Fuel-Consuming Activities for the Energy-Intensive Manufacturing Subsectors

End Use Characterization
Food: direct fuel, hot water/steam, refrigeration, and other energy uses.
Bulk Chemicals: direct fuel, hot water/steam, electrotytic, and other energy uses.
Process Step characterization
Pulp and Paper: wood preparation, waste pulping, mechanical pulping, semi-chemical pulping, kraft pulping, bleaching, and paper making.
Glass: batch preparation, melting/refining, and forming.
Cement: dry process clinker, wet process clinker, and finish grinding.
Steel: coke oven, open hearth steel making, basic oxygen furnace steel making, electric arc furnace steel making, ingot casting, continuous casting, hot rolling, and cold rolling.
Aluminum: primary and secondary (scrap) aluminum smelting, semi-fabrication (e.g. sheet, wire, etc.).

It is assumed that the technical potential for fossil-fuel source CHP is based primarily on supplying thermal requirements. First, the model assesses the amount of capacity that could be added to generate the industrial steam requirements not met by existing CHP. The second step is an economic evaluation of gas turbine prototypes for each steam load segment. Finally, CHP additions are projected based on a range of acceptable payback periods.

The PA component accounts for the largest share of direct energy consumption for heat and power, 55 percent. For the seven most energy-intensive industries, process steps or end uses are modeled using engineering concepts. The production process is decomposed into the major steps, and the energy relationships among the steps are specified.

The energy intensities of the process steps or end uses vary over time, both for existing technology and for technologies expected to be adopted in the future. In IDM, this variation is based on engineering judgement and is reflected in the parameters of technology possibility curves, which show the declining energy intensity of existing and new capital relative to the 2002 stock.

IDM uses "technology bundles" to characterize technological change in the energy-intensive industries. These bundles are defined for each production process step for five of the industries and for end uses in the remaining two energy-intensive industries. The process step industries are pulp and paper, glass, cement, steel, and aluminum. The end-use industries are food and bulk chemicals (see Table 7).

Machine drive electricity consumption in the food, bulk chemicals, metal-based durables, and balance of manufacturing sectors is calculated by a motor stock model. The beginning stock of motors is modified over the projection horizon as motors are added to accommodate growth in shipments for each sector, as motors are retired and replaced, and as failed motors are rewound. When a new motor is added, either to accommodate growth or as a replacement, an economic choice is made between purchasing a motor that meets the EPACT minimum for efficiency or a premium efficiency motor. There are seven motor size groups in each of the four industries. The EPACT efficiency standards only apply to the five smallest groups (up to 200 horsepower). As the motor stock changes over the projection horizon, the overall efficiency of the motor population changes as well.

The Unit Energy Consumption (UEC) is defined as the energy use per ton of throughput at a process step or as energy use per dollar of shipments for the end-use industries. The "Existing UEC" is the current average installed intensity as of 2002. The "New 2002 UEC" is the intensity assumed to prevail for a new installation in 2002. Similarly, the "New 2030 UEC" is the intensity expected to prevail for a new installation in 2030. For intervening years, the intensity is interpolated.

The rate at which the average intensity declines is determined by the rate and timing of new additions to capacity. In IDM, the rate and timing of new additions are functions of retirement rates and industry growth rates.

IDM uses a vintaged capital stock accounting framework that models energy use in new additions to the stock and in the existing stock. This capital stock is represented as the aggregate vintage of all plants built within an industry and does not imply the inclusion of specific technologies or capital equipment.

The capital stock is grouped into three vintages: old, middle, and new. The old vintage consists of capital in production prior to 2002, which is assumed to retire at a fixed rate each year. Middle-vintage capital is that added after 2002. New production capacity is built in the projection years when the capacity of the existing stock of capital in

IDM cannot produce the output projected by the NEMS regional submodule of the macroeconomic activity module. Capital additions during the projection horizon are retired in subsequent years at the same rate as the pre-2002 capital stock.

The energy-intensive and/or large energy-consuming industries are modeled with a structure that explicitly describes the major process flows or "stages of production" in the industry (some industries have major consuming uses).

Technology penetration at the level of major processes in each industry is based on a technology penetration curve relationship. A second relationship can provide additional energy conservation resulting from increases in relative energy prices. Major process choices (where applicable) are determined by industry production, specific process flows, and exogenous assumptions.

Recycling, waste products, and byproduct consumption are modeled using parameters based on off-line analysis and assumptions about the manufacturing processes or technologies applied within industry. These analyses and assumptions are mainly based upon environmental regulations such as government requirements about the share of recycled paper used in offices. IDM also accounts for trends within industry toward the production of more specialized products such as specialized steel which can be produced using scrap material versus raw iron ore.

Transportation Demand Module

Transportation Demand Module

The transportation demand module (TRAN) projects the consumption of transportation sector fuels by transportation mode, including the use of renewables and alternative fuels, subject to delivered prices of energy and macroeconomic variables, including disposable personal income, gross domestic product, level of imports and exports, industrial output, new car and light truck sales, and population. The structure of the module is shown in Figure 8.

Projections of future fuel prices influence fuel efficiency, vehicle-miles traveled, and alternative-fuel vehicle (AFV) market penetration for the current fleet of vehicles. Alternative-fuel vehicle shares are projected on the basis of a multinomial logit model, subject to State and Federal government mandates for minimum AFV sales volumes.

Fuel Economy Submodule

This submodule projects new light-duty vehicle fuel economy by 12 U.S. Environmental Protection Agency (EPA) vehicle size classes and 16 propulsion technologies (gasoline, diesel, and 14 AFV technologies) as a function of energy prices and income-related variables. There are 61 fuel-saving technologies which vary in cost and marginal fuel savings by size class. Characteristics of a sample of these technologies are shown in Table 8, a complete list is published in Assumptions to the Annual Energy Outlook 2009.[14] Technologies penetrate the market based on a cost-effectiveness algorithm that compares the technology cost to the discounted stream of fuel savings and the value of performance to the consumer. In general, higher fuel prices lead to higher fuel efficiency estimates within each size class, a shift to a more fuel-efficient size class mix, and an increase in the rate at which alternative-fuel vehicles enter the marketplace.

Regional Sales Submodule

Vehicle sales from the MAM are divided into car and light truck sales. The remainder of the submodule is a simple accounting mechanism that uses endogenous estimates of new car and light truck sales and the historical regional vehicle sales adjusted for regional population trends to produce estimates of regional sales, which are subsequently passed to the alternative-fuel vehicle and the light-duty vehicle stock submodules.

Alternative-Fuel Vehicle Submodule

This submodule projects the sales shares of alternative-fuel technologies as a function of technology attributes, costs, and fuel prices. The alternative-fuel vehicles attributes are shown in Table 9, derived from *Assumptions to the Annual Energy Outlook 2009*. Both conventional and new technology vehicles are considered. The alternative-fuel vehicle submodule receives regional new car and light truck sales by size class from the regional sales submodule.

The projection of vehicle sales by technology utilizes a nested multinomial logit (NMNL) model that predicts sales shares based on relevant vehicle and fuel attributes. The nesting structure first predicts the probability of fuel choice for multi-fuel vechicles within a technology set. The second level nesting predicts penetration among similar technologies within a technology set (i.e. gasoline versus diesel hybrids). The third level choice determines market share among the the different technology sets.[15]

TRAN Outputs	Inputs from NEMS	Exogenous Inputs
Fuel demand by mode	Energy product prices	Existing vehicle stocks by vintage and fuel economy
Sales, stocks, and characteristics of vehicle types by size class	Gross domestic product	Vehicle survival rates
	Disposable personal income	New vehicle technology characteristics
Vehicle-miles traveled	Industrial output	Fuel availability
Fuel economy by technology type	Vehicle sales	Commercial availability
Alternative-fuel vehicle sales by technology type	International trade	Vehicle safety and emissions reglations
Light-duty commercial fleet vehicle characteristics	Natural gas pipeline	Vehicle miles-per-gallon degradation rates
	Population	

14 Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009* http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2009) (Washington, DC, January 2009).

15 Greene, David L. and S.M. Chin, "Alternative Fuels and Vehicles (AFV) Model Changes," Center for Transportation Analysis, Oak Ridge National Laboratory, page 1, (Oak Ridge, TN, November 14, 2000).

Table 8. Selected Technology Characteristics for Automobiles

	Fractional Fuel Efficiency Change	First Year Introduced	Fractional Horsepower Change
Material Substitution IV	0.099	2006	0
Drag Reduction IV	0.042	2000	0
5-Speed Automatic	0.025	1995	0
CVT	0.052	1998	0
Automated Manual Trans	0.073	2004	0
VVL-6 Clinder	0.033	2000	0.10
Camless Valve Actuation 6 Cylinder	0.058	2020	0.13
Electric Power Steering	0.015	2004	0
42V-Launch Assist and Regen	0.075	2005	-0.05

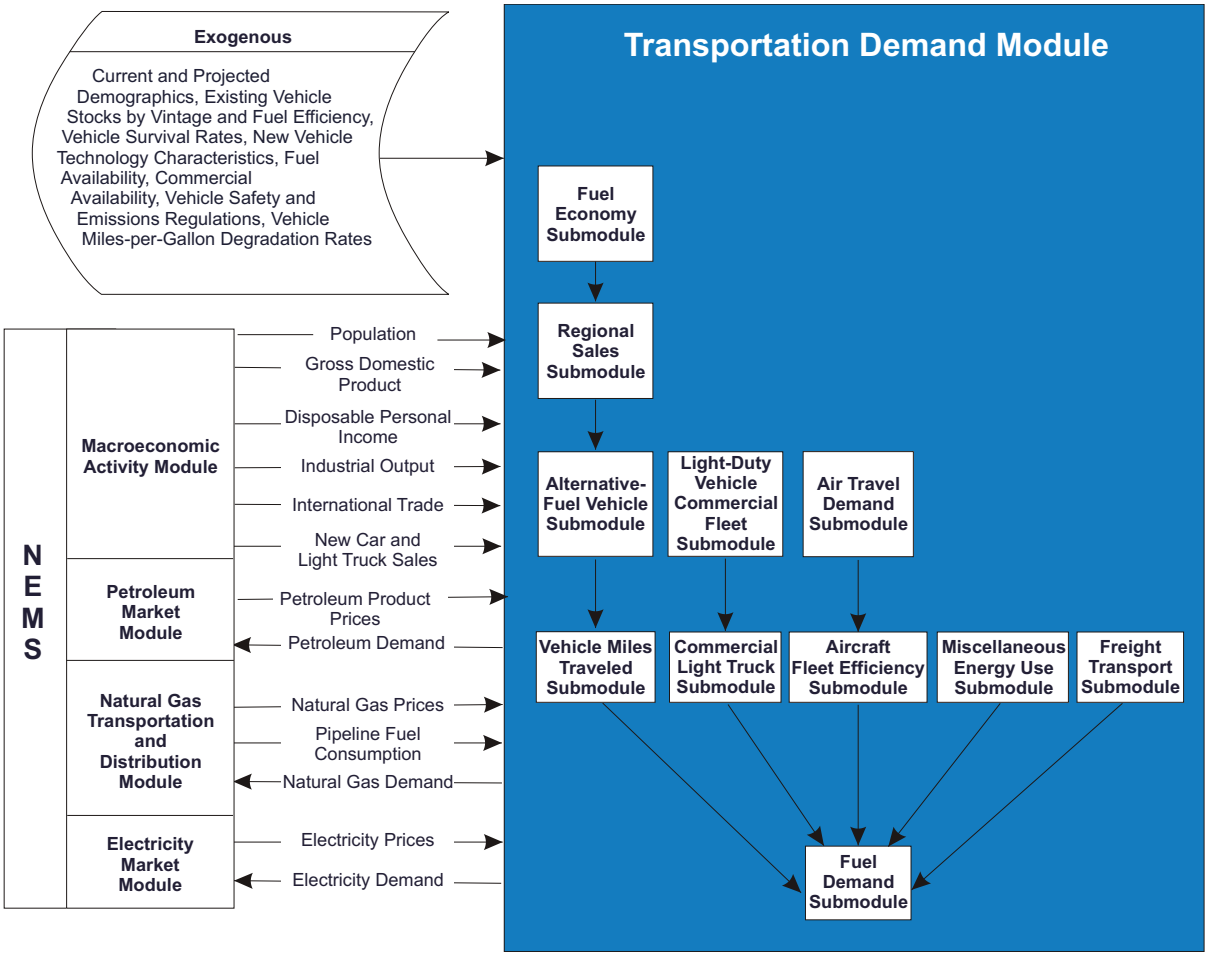
Table 9. Examples of Midsize Automobile Attributes

	Year	Gasoline	TDI Diesel	Ethanol Flex	LPG Bi-Fuel	Electric Gasoline Hybrid	Fuel Cell Hydrogen
Vehicle Price (thousand 2007 dollars)	2006	28.0	29.8	28.7	33.3	31.1	78.6*
	2030	29.8	30.7	30.2	35.0	31.0	54.2
Vehicle Miles per Gallon	2006	29.5	39.8	29.9	29.6	42.7	53.3*
	2030	37.8	48.2	38.1	37.7	51.0	54.9
Vehicle Range (miles)	2006	521	704	381	417	652	594*
	2030	674	910	492	539	843	674

*First year of availability

Transportation Demand Module

Figure 8. Transportation Demand Module Structure



Alternative Fuel Vehicles

Ethanol flex-fueled
Ethanol neat (85 percent ethanol)
Compressed natural gas (CNG)
CNG bi-fuel
Liquefied petroleum gas (LPG)
LPG bi-fuel
Battery electric vehicle
Plug-in hybrid with 10 mile all electric range
Plug-in hybrid with 40 mile all electric range
Gasoline hybrid
Diesel Hybrid
Fuel cell gasoline
Fuel cell hydrogen
Fuel cell methanol

The technology sets include:

- Conventional fuel capable (gasoline, diesel, bi-fuel and flex-fuel),
- Hybrid (gasoline and diesel) and plug-in hybrid
- Dedicated alternative fuel (compressed natural gas (CNG), liquified petroleum gas (LPG), and ethanol),
- Fuel cell (gasoline, methanol, and hydrogen),
- Electric battery powered (nickel-metal hydride, lithium)

The vehicles attributes considered in the choice algorithm include: price, maintenance cost, battery replacement cost, range, multi-fuel capability, home refueling capability, fuel economy, acceleration and luggage space.

With the exception of maintenance cost, battery replacement cost, and luggage space, vehicle attributes are determined endogenously.[16] The fuel attributes used in market share estimation include availability and price. Vehicle attributes vary by six EPA size classes for cars and light trucks and fuel availability varies by Census division. The NMNL model coefficients were developed to reflect purchase preferences for cars and light trucks separately.

Light-Duty Vehicle (LDV) Stock Submodule

This submodule specifies the inventory of LDVs from year to year. Survival rates are applied to each vintage, and new vehicle sales are introduced into the vehicle stock through an accounting framework. The fleet of vehicles and their fuel efficiency characteristics are important to the translation of transportation services demand into fuel demand.

TRAN maintains a level of detail that includes twenty vintage classifications and six passenger car and six light truck size classes corresponding to EPA interior volume classifications for all vehicles less than 8,500 pounds,

Light Duty Vehicle Size Classes

Cars:
- Mini-compact - less than 85 cubic feet
- Subcompact - between 85 and 99 cubic feet
- Compact - between 100 and 109 cubic feet
- Mid-size - between 110 and 119 cubic feet
- Large - 120 or more cubic feet
- Two-seater - designed to seat two adults

Trucks:
- Small vans - gross vehicle weight rating (GVWR) less than 4,750 pounds
- Large vans - GVWR 4,750 to 8,500 pounds
- Small pickups - GVWR less than 4,750 pounds
- Large pickups - GVWR 4,750 to 8,500 pounds
- Small utility - GVWR less than 4,750 pounds
- Large utility - GVWR 4,750 to 8,500 pounds

as follows:

Vehicle-Miles Traveled (VMT) Submodule

This submodule projects travel demand for automobiles and light trucks. VMT per capita estimates are based on the fuel cost of driving per mile and per capita disposable personal income. Total VMT is calculated by multiplying VMT by the number of licensed drivers.

LDV Commercial Fleet Submodule

This submodule generates estimates of the stock of cars and trucks used in business, government, and utility fleets. It also estimates travel demand, fuel efficiency, and energy consumption for the fleet vehicles prior to their transition to the private sector at predetermined vintages.

Commercial Light Truck Submodule

The commercial light truck submodule estimates sales, stocks, fuel efficiencies, travel, and fuel demand for all trucks greater than 8,500 pounds and less than 10,000 pounds gross vehicle weight rating.

Air Travel Demand Submodule

This submodule estimates the demand for both passenger and freight air travel. Passenger travel is projected by domestic travel (within the U.S.), international travel (between U.S. and Non U.S.), and Non U.S. travel. Dedicated air freight travel is estimated for U.S. and Non U.S. demand. In each of the market segments, the demand for air travel is estimated as a function of the cost of air travel (including fuel costs) and economic growth (GDP, disposable income, and merchandise exports).

Aircraft Fleet Efficiency Submodule

This submodule projects the total world-wide stock and the average fleet efficiency of narrow body, wide body, and regional jets required to meet the projected travel demand. The stock estimation is based on the growth of travel demand and the flow of aircraft into and out of the United States The overall fleet efficiency is determined by the weighted average of the surviving aircraft efficiency (including retrofits) and the efficiencies of the newly acquired aircraft. Efficiency improvements of new aircraft are determined by projecting the market penetration of advanced aircraft technologies.

16 Energy and Environmental Analysis, Inc., Updates to the Fuel Economy Model (FEM) and Advanced Technology Vehicle (ATV:) Module of the National Energy Modeling System (NEMS) Transportation Model, prepared for the Energy Information Administration (EIA),

Freight Transport Submodule

This submodule translates NEMS estimates of industrial production into ton-miles traveled for rail and ships and into vehicle vehicle-miles traveled for trucks, then into fuel demand by mode of freight travel. The freight truck stock is subdivided into medium and heavy-duty trucks. VMT freight estimates by truck size class and technology are based on matching freight needs, as measured by the growth in industrial output by NAICS code, to VMT levels associated with truck stocks and new vehicles. Rail and shipping ton-miles traveled are also estimated as a function of growth in industrial output.

Freight truck fuel efficiency growth rates are tied to historical growth rates by size class and are also dependent on the maximum penetration, introduction year, fuel trigger price (based on cost-effectiveness), and fuel economy improvement of advanced technologies, which include alternative-fuel technologies. A subset of the technology characteristics are shown in Table 10. In the rail and shipping modes, energy efficiency estimates are structured to evaluate the potential of both technology trends and efficiency improvements related to energy prices.

Miscellaneous Energy Use Submodule

This submodule projects the use of energy in military operations, mass transit vehicles, recreational boats, and lubricants, based on endogenous variables within NEMS (e.g., vehicle fuel efficiencies) and exogenous variables (e.g., the military budget).

Table 10. Example of Truck Technology Characteristics (Diesel)

	Fuel Economy Improvement (percent)		Maximum Penetration (percent)		Introduction Year		Capital Cost (2001 dollars)	
	Medium	Heavy	Medium	Heavy	Medium	Heavy	Medium	Heavy
Aero Dynamics: bumper, underside air battles, wheel well covers	3.6	2.3	50	40	2002	N/A	N/A	$1,500
Low rolling resistence tires	2.3	2.7	50	66	2004	2005	$180	$550
Transmission: lock-up, electronic controls, reduced friction	1.8	1.8	100	100	2005	2005	$750	$1,000
Diesel Engine: hybrid electric powertrain	36.0	N/A	15	N/A	2010	N/A	$6,000	N/A
Reduce waste heat, thermal mgmt	N/A	9.0	N/A	35	N/A	2010	N/A	$2,000
Weight reduction	4.5	9.0	20	30	2010	2005	$1,300	$2,000
Diesel Emission No_x non-thermal plasma catalyst	-1.5	-1.5	25	25	2007	2007	$1,000	$1,250
PM catalytic filter	-2.5	-1.5	95	95	2008	2006	$1,000	$1,500
HC/CO: oxidation catalyst	-0.5	-0.5	95	95	2002	2002	$150	$250
NO_x adsorbers	-3.0	-3.0	90	90	2007	2007	$1,500	$2,500

Electricity Market Module

Electricity Market Module

The electricity market module (EMM) represents the generation, transmission, and pricing of electricity, subject to: delivered prices for coal, petroleum products, and natural gas; the cost of centralized generation from renewable fuels; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. The submodules consist of capacity planning, fuel dispatching, finance and pricing, and load and demand (Figure 9). In addition, nonutility supply and electricity trade are represented in the fuel dispatching and capacity planning submodules. Nonutility generation from CHP and other facilities whose primary business is not electricity generation is represented in the demand and fuel supply modules. All other nonutility generation is represented in the EMM. The generation of electricity is accounted for in 15 supply regions (Figure 10), and fuel consumption is allocated to the 9 Census divisions.

The EMM determines airborne emissions produced by the generation of electricity. It represents limits for sulfur dioxide and nitrogen oxides specified in the Clean Air Act Amendments of 1990 (CAAA90) and the Clean Air Interstate Rule. The *AEO2009* also models State-level regulations implementing mercury standards. The EMM also has the ability to track and limit emissions of carbon dioxide, and the *AEO2009* includes the regional carbon restrictions of the Regional Greenhouse Gas Initiative (RGGI).

Operating (dispatch) decisions are provided by the cost-minimizing mix of fuel and variable operating and maintenance (O&M) costs, subject to environmental costs. Capacity expansion is determined by the least-cost mix of all costs, including capital, O&M, and fuel. Electricity demand is represented by load curves, which vary by region and season. The solution to the submodules of EMM is simultaneous in that, directly or indirectly, the solution for each submodule depends on the solution to every other submodule. A solution sequence through the submodules can be viewed as follows:

- The electricity load and demand submodule processes electricity demand to construct load curves
- The electricity capacity planning submodule projects the construction of new utility and nonutility plants, the level of firm power trades, and the addition of equipment for environmental compliance
- The electricity fuel dispatch submodule dispatches the available generating units, both utility and nonutility, allowing surplus capacity in select regions to be dispatched to meet another regions needs (economy trade)
- The electricity finance and pricing submodule calculates total revenue requirements for each operation and computes average and marginal-cost based electricity prices.

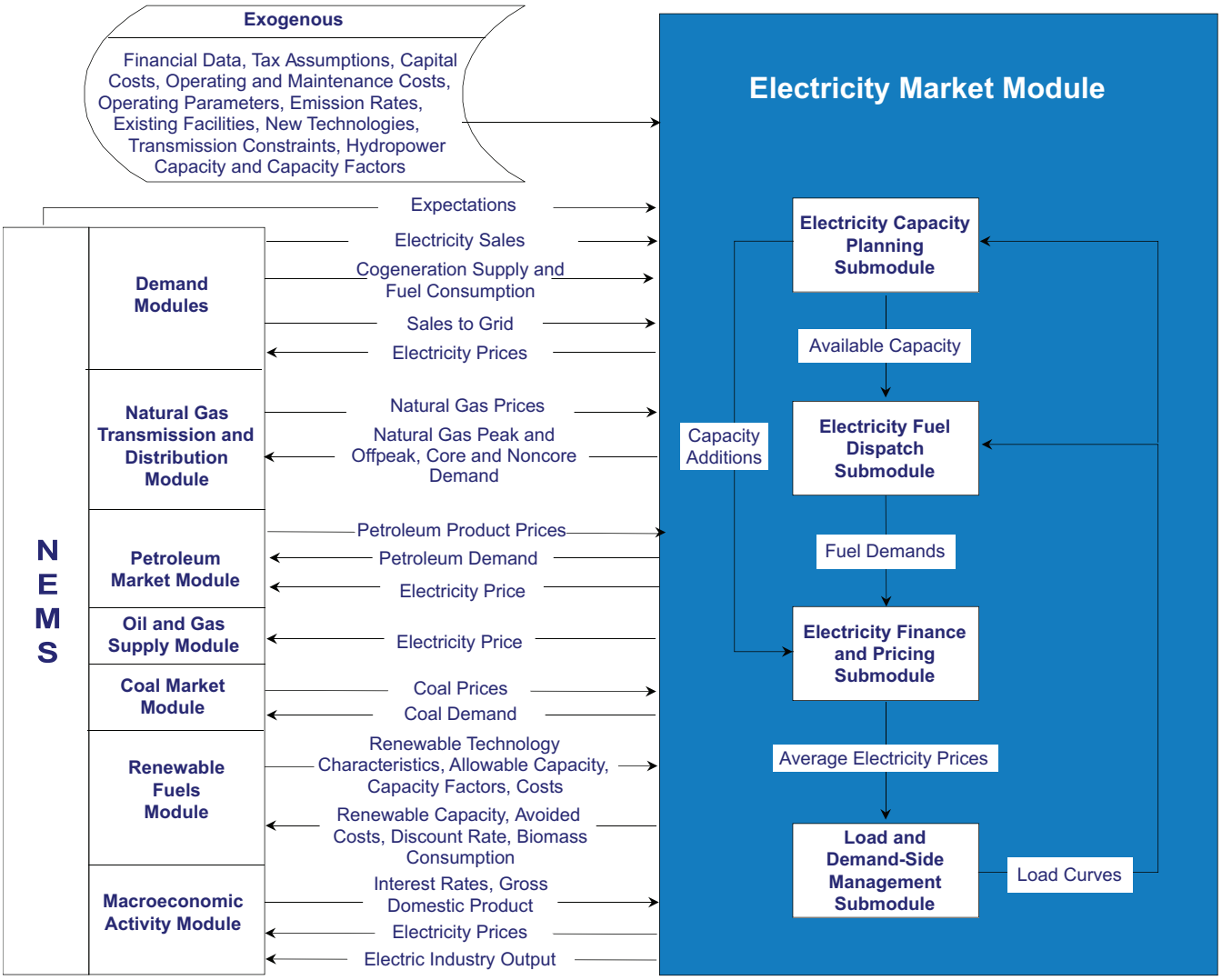
Electricity Capacity Planning Submodule

The electricity capacity planning (ECP) submodule determines how best to meet expected growth in electricity demand, given available resources, expected load shapes, expected demands and fuel prices, environmental constraints, and costs for utility and nonutility technologies. When new capacity is required to meet growth in electricity demand, the technology chosen is determined by the timing of the demand increase, the expected utilization of the new capacity, the operating efficiencies, and the construction and operating costs of available technologies.

The expected utilization of the capacity is important in the decision-making process. A technology with relatively high capital costs but comparatively low operating costs (primarily fuel costs) may be the appropriate choice if the capacity is expected to operate continuously (base load). However, a plant type with high operating costs but low capital costs may be the most economical selection to serve the peak load (i.e., the highest demands on the system), which occurs infrequently. Intermediate or cycling load occupies a middle ground between base and peak load and is best served

EMM Outputs	Inputs from NEMS	Exogenous Inputs
Electricity prices and price components	Electricity sales	Financial data
Fuel demands	Fuel prices	Tax assumptions
Capacity additions	Cogeneration supply and fuel consumption	Capital costs
Capital requirements	Electricity sales to the grid	Operation and maintenance costs
Emissions	Renewable technology characteristics, allowable capacity, and costs	Operating parameters
Renewable capacity	Renewable capacity factors	Emmissions rates
Avoided costs	Gross domestic product	New technologies
	Interest rates	Existing facilities
		Transmission constraints

Figure 9. Electricity Market Module Strucuture



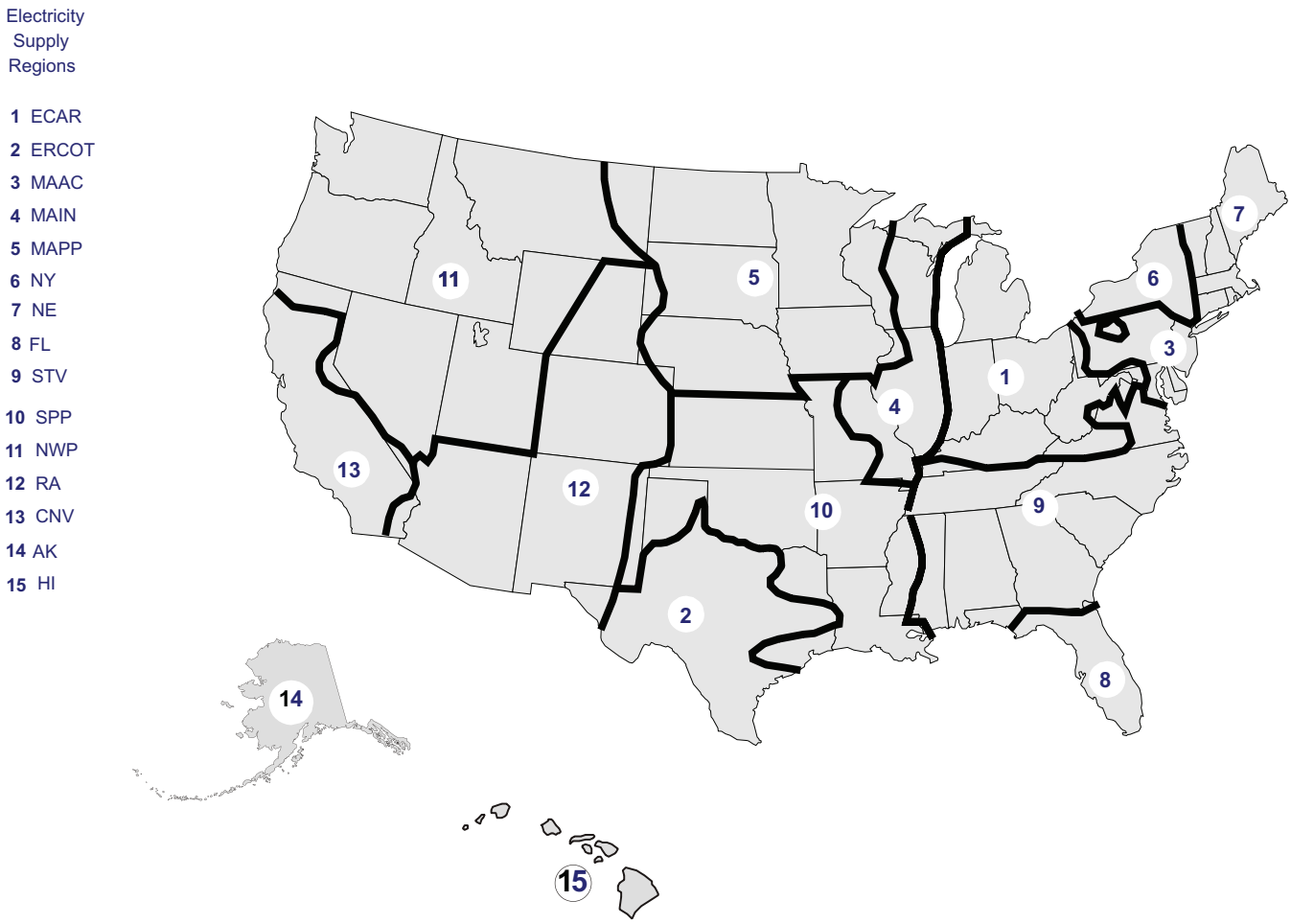
by plants that are cheaper to build than baseload plants and cheaper to operate than peak load plants.

Technologies are compared on the basis of total capital and operating costs incurred over a 20-year period. As new technologies become available, they are competed against conventional plant types. Fossil-fuel, nuclear, and renewable central-station generating technologies are represented, as listed in Table 11. The EMM also considers two distributed generation technologies -baseload and peak. The EMM also has the ability to model a demand storage technology to represent load shifting.

Uncertainty about investment costs for new technologies is captured in ECP using technological optimism and learning factors. The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.

Learning factors represent reductions in capital costs due to learning-by-doing. For new technologies, cost reductions due to learning also account for international experience in building generating capacity. These factors

Figure 10. Electricity Market Module Supply Regions



are calculated for each of the major design components of a plant type design. For modeling purposes, components are identified only if the component is shared between multiple plant types, so that the ECP can reflect the learning that occurs across technologies. The cost adjustment factors are based on the cumulative capacity of a given component. A 3-step learning curve is utilized for all design components.

Typically, the greatest amount of learning occurs during the initial stages of development and the rate of cost reductions declines as commercialization progresses. Each step of the curve is characterized by the learning rate and the number of doublings of capacity in which this rate is applied. Depending on the stage of development for a particular component, some of the learning may already be incorporated in the initial cost estimate.

Capital costs for all new electricity generating technologies (fossil, nuclear, and renewable) decrease in response to foreign and domestic experience. Foreign units of new technologies are assumed to contribute to reductions in capital costs for units that are installed in the United States to the extent that (1) the technology characteristics are similar to those used in U.S. markets, (2) the design and construction firms and key personnel compete in the U.S. market, (3) the owning and operating firm competes actively in the United States, and (4) there exists relatively complete information about the status of the associated facility. If the new foreign units do not satisfy one or more of these requirements, they are given a reduced weight or not included in the learning effects calculation. Capital costs, heat rates, and first year of availablilty from the *AEO2009* reference case are shown in Table 12; capital costs represent the costs of building

new plants ordered in 2008. Additional information about costs and performance characteristics can be found on page 89 of the "Assumptions to the Annual Energy Outlook 2009."[17]

Initially, investment decisions are determined in ECP using cost and performance characteristics that are represented as single point estimates corresponding to the average (expected) cost. However, these parameters are also subject to uncertainty and are better represented by distributions. If the distributions of two or more options overlap, the option with the lowest average cost is not likely to capture the entire market. Therefore, ECP uses a market-sharing algorithm to adjust the initial solution and reallocate some of the capacity expansion decisions to technologies that are competitive but do not have the lowest average cost.

Fossil-fired steam and nuclear plant retirements are calculated endogenously within the model. Plants are retired if the market price of electricity is not sufficient to support continued operation. The expected revenues from these plants are compared to the annual going-forward costs, which are mainly fuel and O&M costs. A plant is retired if these costs exceed the revenues and the overall cost of electricity can be reduced by building replacement capacity.

The ECP submodule also determines whether to contract for unplanned firm power imports from Canada and from neighboring electricity supply regions. Imports from Canada are competed using supply curves developed from cost estimates for potential hydroelectric projects in Canada. Imports from neighboring electricity supply regions are competed in the ECP based on the cost of the unit in the exporting region plus the additional cost of transmitting the power. Transmission costs are computed as a fraction of revenue.

After building new capacity, the submodule passes total available capacity to the electricity fuel dispatch submodule and new capacity expenses to the electricity finance and pricing submodule.

Electricity Fuel Dispatch Submodule

Given available capacity, firm purchased-power agreements, fuel prices, and load curves, the electricity fuel dispatch (EFD) submodule minimizes variable costs as it solves for generation facility utilization and economy power exchanges to satisfy demand in each time period and region. Limits on emissions of sulfur dioxide from generating units and the engineering characteristics of units serve as constraints. Coal-fired capacity can co-fire with biomass in order to lower operating costs and/or emissions.

The EFD uses a linear programming (LP) approach to provide a minimum cost solution to allocating (dispatching) capacity to meet demand. It simulates the electric transmission network on the NERC region level and simultaneously dispatches capacity regionally by time slice until demand for the year is met. Traditional cogeneration and firm trade capacity is removed from the load duration curve prior to the dispatch decision. Capacity costs for each time slice are based on fuel and variable O&M costs, making adjustments for RPS

Table 11. Generating Technologies

Fossil
Existing coal steam plants (with or without environmental controls) New pulverized coal with environmental controls Advanced clean coal technology Advanced clean coal technology with sequestration Oil/Gas steam Conventional combined cycle Advanced combined cycle Advanced combined cycle with sequestration Conventional combusion turbine Fuel cells
Nuclear
Conventional nuclear Advanced nuclear
Renewables
Conventional hydropower Pumped storage Geothermal Solar-thermal Solar-photovoltaic Wind - onshore and offshore Wood Municipal solid waste
Environmental controls include flue gas desulfurization (FGD), selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), fabric filters, spray cooling, activated carbon injection (ACI), and particulate removal equipiment.

17 Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2009).pdf (March 2009)

credits, if applicable, and production tax credits. Generators are required to meet planned maintenance requirements, as defined by plant type.

Interregional economy trade is also represented in the EFD submodule by allowing surplus generation in one region to satisfy electricity demand in an importing region, resulting in a cost savings. Economy trade with Canada is determined in a similar manner as interregional economy trade. Surplus Canadian energy is allowed to displace energy in an importing region if it results in a cost savings. After dispatching, fuel use is reported back to the fuel supply modules and operating expenses and revenues from trade are reported to the electricity finance and pricing submodule.

Electricity Finance and Pricing Submodule

The costs of building capacity, buying power, and generating electricity are tallied in the electricity finance and pricing (EFP) submodule, which simulates both competitive electricity pricing and the cost-of-service method often used by State regulators to determine the price of electricity. The AEO2009 reference case assumes a transition to full competitive pricing in New York, Mid-Atlantic Area Council, and Texas, and a 95 percent transition to competitive pricing in New England (Vermont being the only fully-regulated State in that region). California returned to almost fully regulated pricing in 2002, after beginning a transition to competition in 1998. In addition electricity prices in the

Table 12. 2008 Overnight Capital Costs (including Contingencies), 2008 Heat Rates, and Online Year by Technology for the AEO2009 Reference Case

Technology	Capital Costs[1] (2007$/KW)	Heatrate in 2008 (Btu/kWhr)	Online Year[2]
Scrubbed Coal New	2058	9200	2012
Integrated Coal-gasification Comb Cycle (IGCC)	2378	8765	2012
IGCC with carbon sequestration	3496	10781	2016
Coventional Gas/Oil Comb Cycle	962	7196	2011
Advanced Gas/Oil Comb Cycle (CC)	948	6752	2011
Advanced CC with carbon sequestration	1890	8613	2016
Conventional Combusion Turbine	670	10810	2010
Advanced Combusition Turbine	634	9289	2010
Fuel Cells	5360	7930	2011
Adv nuclear	3318	10434	2016
Distributed Generation - Base	1370	9050	2011
Distributed Generation - Peak	1645	10069	2010
Biomass	3766	9646	2012
MSW - Landfill Gas	2543	13648	2010
Geothermal[3]	1711	34633	2010
Conventional Hydropower [3,4]	2242	9919	2012
Wind[4]	1923	9919	2009
Wind Offshore[4]	3851	9919	2012
Solar Thermal	5021	9919	2012
Photovoltaic	6038	9919	2011

[1]Overnight capital cost including contingency factors, excluding reigonal multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2008. Capital costs are shown before investment tax credits are applied, where applicable.

[2]Online year represents the first year that a new unit could be completed, given an order date of 2008. For wind, geothermal and landfill gas, the online year was moved earlier to acknowledge the significant market activity already occuring in anticipation of the expiration of the Production Tax Credit in 2009 for wind and 2010 for the others.

[3]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[4]For hydro, wind, and solar technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2007. This isused for purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.

East Central Area Reliability Council, the Mid-American Interconnected Network, the Southeastern Electric Reliability Council, the Southwest Power Pool, the Northwest Power Pool, and the Rocky Mountain Power Area/Arizona are a mix of both competitive and regulated prices. Since some States in each of these regions have not taken action to deregulate their pricing of electricity, prices in those States are assumed to continue to be based on traditional cost-of-service pricing. The price for mixed regions is a load-weighted average of the competitive price and the regulated price, with the weight based on the percent of electricity load in the region that has taken action to deregulate. In regions where none of the states in the region have introduced competition—Florida Reliability Coordinating Council and Mid-Continent Area Power Pool—electricity prices are assumed to remain regulated and the cost-of-service calculation is used to determine electricity prices.

Using historical costs for existing plants (derived from various sources such as Federal Energy Regulatory Commission Form 1, Annual Report of Major Electric Utilities, Licensees and Others, and Form EIA-412, Annual Report of Public Electric Utilities), cost estimates for new plants, fuel prices from the NEMS fuel supply modules, unit operating levels, plant decommissioning costs, plant phase-in costs, and purchased power costs, the EFP submodule calculates total revenue requirements for each area of operation—generation, transmission, and distribution—for pricing of electricity in the fully regulated States. Revenue requirements shared over sales by customer class yield the price of electricity for each class. Electricity prices are returned to the demand modules. In addition, the submodule generates detailed financial statements.

For those States for which it is applicable, the EFP also determines competitive prices for electricity generation. Unlike cost-of-service prices, which are based on average costs, competitive prices are based on marginal costs. Marginal costs are primarily the operating costs of the most expensive plant required to meet demand. The competitive price also includes a reliability price adjustment, which represents the value consumers place on reliability of service when demands are high and available capacity is limited. Prices for transmission and distribution are assumed to remain regulated, so the delivered electricity price under competition is the sum of the marginal price of generation and the average price of transmission and distribution.

Electricity Load and Demand Submodule

The electricity load and demand (ELD) submodule generates load curves representing the demand for electricity. The demand for electricity varies over the course of a day. Many different technologies and end uses, each requiring a different level of capacity for different lengths of time, are powered by electricity. For operational and planning analysis, an annual load duration curve, which represents the aggregated hourly demands, is constructed. Because demand varies by geographic area and time of year, the ELD submodule generates load curves for each region and season.

Emissions

EMM tracks emission levels for sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Facility development, retrofitting, and dispatch are constrained to comply with the pollution constraints of the CAAA90 and other pollution constraints including the Clean Air Interstate Rule. An innovative feature of this legislation is a system of trading emissions allowances. The trading system allows a utility with a relatively low cost of compliance to sell its excess compliance (i.e., the degree to which its emissions per unit of power generated are below maximum allowable levels) to utilities with a relatively high cost of compliance. The trading of emissions allowances does not change the national aggregate emissions level set by CAAA90, but it does tend to minimize the overall cost of compliance.

In addition to SO_2, and NO_x, the EMM also determines mercury and carbon dioxide emissions. It represents control options to reduce emissions of these four gases, either individually or in any combination. Fuel switching from coal to natural gas, renewables, or nuclear can reduce all of these emissions. Flue gas desulfurization equipment can decrease SO_2 and mercury emissions. Selective catalytic reduction can reduce NO_x and mercury emissions. Selective non-catalytic reduction and low-NO_x burners can lower NO_x emissions. Fabric filters and activated carbon injection can reduce mercury emissions. Lower emissions resulting from demand reductions are determined in the end-use demand modules.

The *AEO2009* includes a generalized structure to model current state-level regulations calling for the best available control technology to control mercury. The *AEO2009* also includes the carbon caps for States that are part of the RGGI.

Renewable Fuels Module

Renewable Fuels Module

The renewable fuels module (RFM) represents renewable energy resoures and large–scale technologies used for grid-connected U.S. electricity supply (Figure 11). Since most renewables (biomass, conventional hydroelectricity, geothermal, landfill gas, solar photovoltaics, solar thermal, and wind) are used to generate electricity, the RFM primarily interacts with the electricity market module (EMM).

New renewable energy generating capacity is either model–determined or based on surveys or other published information. A new unit is only included in surveys or acccepted from published information if it is reported to or identified by the EIA and the unit meets EIA criteria for inclusion (the unit exists, is under construction, under contract, is publicly declared by the vendor, or is mandated by state law, such as under a state renewable portfolio standard). EIA may also assume minimal builds for reasons based on historical experience (floors). The penetration of grid-connected renewable energy generating technologies, with the exception of landfill gas, is determined by the EMM.

Each renewable energy submodule of the RFM is treated independently of the others, except for their least-cost competition in the EMM. Because variable operation and maintenance costs for renewable technologies are lower than for any other major generating technology, and because they generally produce little or no air pollution, all available renewable capacity, except biomass, is assumed to be dispatched first by the EMM. Because of its potentially significant fuel cost, biomass is dispatched according to its variable cost by the EMM.

With significant growth over time, installation costs are assumed to be higher because of growing constraints on the availability of sites, natural resource degradation, the need to upgrade existing transmission or distribution networks, and other resource-specific factors.

Geothermal-Electric Submodule

The geothermal-electric submodule provides the EMM the amounts of new geothermal capacity that can be built at known and well characterized geothermal resource sites, along with related cost and performance data. The information is expressed in the form of a three–step supply function that represents the aggregate amount of new capacity and associated costs that can be offered in each year in each region.

Only hydrothermal (hot water and steam) resources are considered. Hot dry rock resources are not included, because they are not expected to be economically accessible during the NEMS projection horizon.

Capital and operating costs are estimated separately, and life-cycle costs are calculated by the RFM. The costing methodology incorporates any applicable effects of Federal and State energy tax construction and production incentives

Wind-Electric Submodule

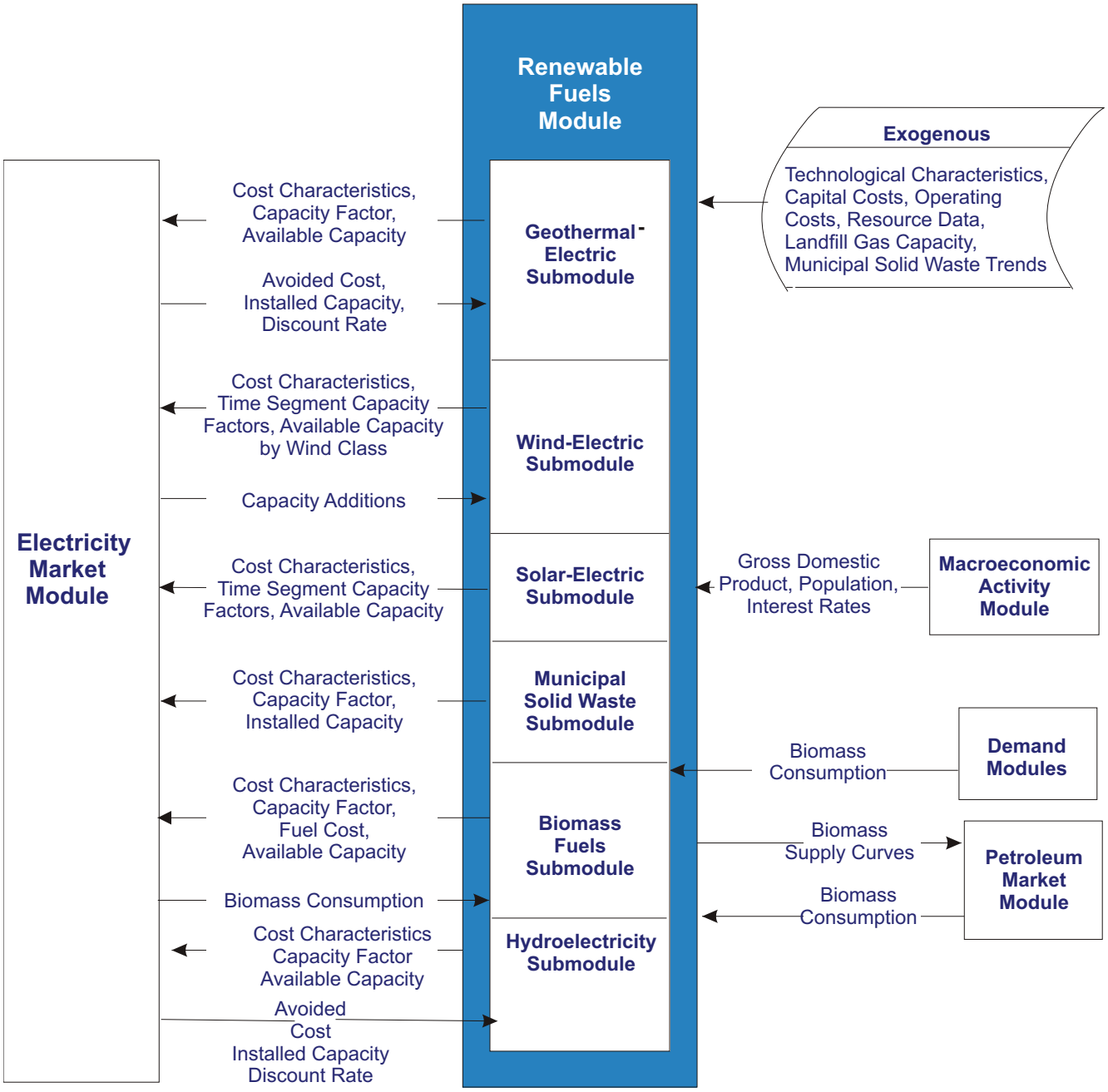
The wind-electric submodule projects the availability of wind resources as well as the cost and performance of wind turbine generators. This information is passed to EMM so that wind turbines can be built and dispatched in competition with other electricity generating technologies. The wind turbine data are expressed in the form of energy supply curves that provide the maximum amount, capital cost, and capacity factor of turbine generating capacity that could be installed in a region in a year, given the available land area and wind speed. The model also evaluates the contribution of the wind capacity to meeting system reliability requirements so that the EMM can appropriately incorporate wind capacity into calculations for regional reliability reserve margins.

Solar-Electric Submodule

The solar-electric submodule represents both photovoltaic and high-temperature thermal electric (concen-

RFM Outputs	Inputs from NEMS	Exogenous Inputs
Energy production capacities	Installed energy production capacity	Site-specific geothermal resource quantity data
Capital costs	Gross domestic product	Site-specific wind resource quality data
Operating costs (including wood supply prices for the wood submodule)	Population	Plant utilization (capacity factor)
	Interest Rates	Technology cost and performance parameters
Capacity factors	Avoided cost of electricity	Landfill gas capacity
Available capacity	Discount rate	
Biomass fuel costs	Capacity additions	
Biomass supply curves	Biomass consumption	

Figure 11. Renewable Fuels Module Structure



trating solar power) installations. Only central-station, grid-connected applications constructed by a utility or independent power producer are considered in this portion of the model.

The solar-electric submodule provides the EMM with time-of-day and seasonal solar availability data for each region, as well as current costs. The EMM uses this data to evaluate the cost and performance of solar-electric technologies in regional grid applications. The commercial and residential demand modules of NEMS also model photovoltaic systems installed by consumers, as discussed in the demand module descriptions under "Distributed Generation."

Landfill Gas Submodule

The landfill gas submodule provides annual projections of electricity generation from methane from landfills (landfill gas). The submodule uses the quantity of municipal solid waste (MSW) that is produced, the proportion of MSW that will be recycled, and the methane emission characteristics of three types of landfills to produce projections of the future electric power generating capacity from landfill gas. The amount of methane available is calculated by first determining the amount of total waste generated in the United States. The amount of total waste generated is derived from an econometric equation that uses gross domestic product and population as the projection drivers. It is assumed that no new mass burn waste–to–energy (MSW) facilities will be built and operated during the projection period in the United States. It is also assumed that operational mass-burn facilities will continue to operate and retire as planned throughout the projection period. The landfill gas submodule passes cost and performance characteristics of the landfill gas–to–electricity technology to the EMM for capacity planning decisions. The amount of new land-fill-gas-to-electricity capacity competes with other technologies using supply curves that are based on the amount of high, medium, and low methane producing landfills located in each EMM region.

Biomass Fuels Submodule

The biomass fuels submodule provides biomass-fired plant technology characterizations (capital costs, operating costs, capacity factors, etc.) and fuel information for EMM, thereby allowing biomass-fueled power plants to compete with other electricity generating technologies.

Biomass fuel prices are represented by a supply curve constructed according to the accessibility of resources to the electricity generation sector. The supply curve employs resource inventory and cost data for four categories of biomass fuel - urban wood waste and mill residues, forest residues, energy crops, and agricultural residues. Fuel distribution and preparation cost data are built into these curves. The supply schedule of biomass fuel prices is combined with other variable operating costs associated with burning biomass. The aggregate variable cost is then passed to EMM.

Hydroelectricity Submodule

The hydroelectricity submodule provides the EMM the amounts of new hydroelectric capacity that can be built at known and well characterized sites, along with related cost and performance data. The information is expressed in the form of a three–step supply function that represents the aggregate amount of new capacity and associated costs that can be offered in each year in each region. Sites include undeveloped stretches of rivers, existing dams or diversions that do not currently produce power, and existing hydroelectric plants that have known capability to expand operations through the addition of new generating units. Capacity or efficiency improvements through the replacement of existing equipment or changes to operating procedures at a facility are not included in the hydroelectricity supply.

Oil And Gas Supply Module

Oil and Gas Supply Module

The OGSM consists of a series of process submodules that project the availability of domestic crude oil production and dry natural gas production from onshore, offshore, and Alaskan reservoirs, as well as conventional gas production from Canada. The OGSM regions are shown in Figure 12.

The driving assumption of OGSM is that domestic oil and gas exploration and development are undertaken if the discounted present value of the recovered resources at least covers the present value of taxes and the cost of capital, exploration, development, and production. Crude oil is transported to refineries, which are simulated in the PMM, for conversion and blending into refined petroleum products. The individual submodules of the OGSM are solved independently, with feedbacks achieved through NEMS solution iterations (Figure 13).

Technological progress is represented in OGSM through annual increases in the finding rates and success rates, as well as annual decreases in costs. For conventional onshore, a time trend was used in econometrically estimated equations as a proxy for technology. Reserve additions per well (or finding rates) are projected through a set of equations that distinquish between new field discoveries and discoveries (extensions) and revisions in known fields. The finding rate equations capture the impacts of technology, prices, and declining resources. Another representation of technology is in the success rate equations. Success rates capture the impact of technology and saturation of the area through cumulative drilling. Technology is further represented in the determination of drilling, lease equipment, and operating costs. Technological progress puts downward pressure on the drilling, lease equipment, and operating cost projections. For unconventional gas, a series of eleven different technology groups are represented by time–dependent adjustments to factors which influence finding rates, success rates, and costs.

Conventional natural gas production in Western Canada is modeled in OGSM with three econometrically estimated equations: total wells drilled, reserves added per well, and expected production-to-reserves ratio. The model performs a simple reserves accounting and applies the expected production-to-reserve ratio to estimate an expected production level, which in turn is used to establish a supply curve for conventional Western Canada natural gas. The rest of the gas production sources in Canada are represented in the Natural Gas Transmission and Distribution Module (NGTDM).

Lower 48 Onshore and Shallow Offshore Supply Submodule

The lower 48 onshore supply submodule projects crude oil and natural gas production from conventional recovery techniques. This submodule accounts for drilling, reserve additions, total reserves, and production -to-reserves ratios for each lower 48 onshore supply region.

The basic procedure is as follows:

- First, the prospective costs of a representative drilling project for a given fuel category and well class within a given region are computed. Costs are a function of the level of drilling activity, average well depth, rig availability, and the effects of technological progress.
- Second, the present value of the discounted cash flows (DCF) associated with the representative project is computed. These cash flows include both the capital and operating costs of the project, including royalties and taxes, and the revenues derived from a declining well production profile, computed after taking into account the progressive effects of resource depletion and valued at constant real prices as of the year of initial valuation.
- Third, drilling levels are calculated as a function of projected profitability as measured by the projected DCF levels for each project and national level cashflow.

OGSM Outputs	Inputs from NEMS	Exogenous Inputs
Crude oil production	Domestic and Canadian natural gas production and wellhead prices	Resource levels
Domestic nonassociated and Canadian conventional natural gas suply curves	Crude oil demand	Initial finding rate parameters and costs
Cogeneration from oil and gas producton	World oil price	Production profiles
Reserves and reserve additions	Electricity price	Tax parameters
Drilling levels	Gross domestic product	
Domestic associated-dissolved gas production	Inflation rate	

Figure 12. Oil and Gas Supply Module Regions



- Fourth, regional finding rate equations are used to project new field discoveries from new field wildcats, new pools, and extensions from other exploratory drilling, and reserve revisions from development drilling.
- Fifth, production is determined on the basis of reserves, including new reserve additions, previous productive capacity, flow from new wells, and, in the case of natural gas, fuel demands. This occurs within the market equilibration of the NGTDM for natural gas and within OGSM for oil.

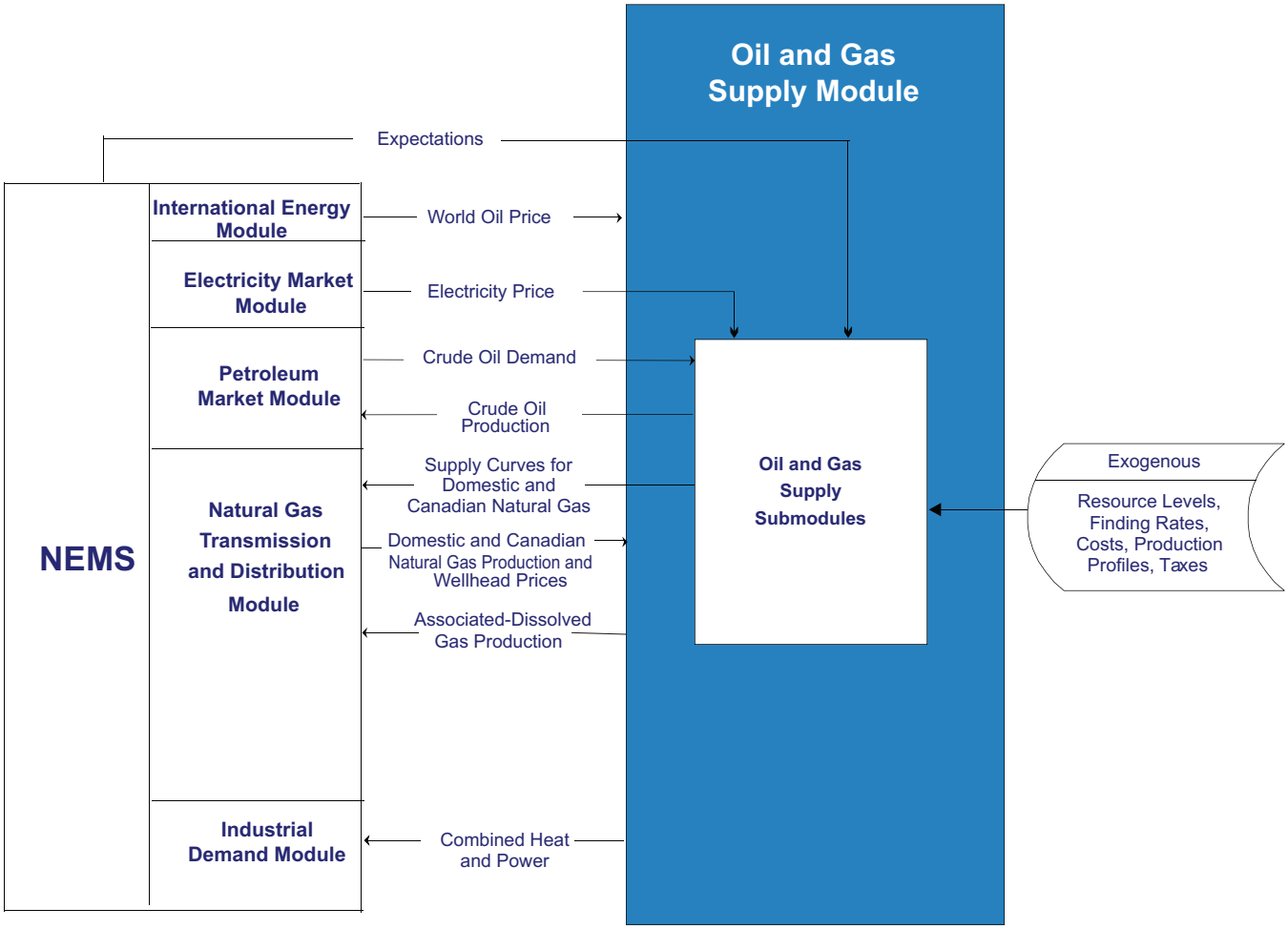
Unconventional Gas Recovery Supply Submodule

Unconventional gas is defined as gas produced from nonconventional geologic formations, as opposed to conventional (sandstones) and carbonate rock formations. The three unconventional geologic formations considered are low–permeability or tight sandstones, gas shales and coalbed methane.

For unconventional gas, a play–level model calculates the economic feasibility of individual plays based on locally specific wellhead prices and costs, resource quantity and quality, and the various effects of technology on both resources and costs. In each year, an initial resource characterization determines the expected ultimate recovery (EUR) for the wells drilled in a particular play. Resource profiles are adjusted to reflect assumed technological impacts on the size, availability, and industry knowledge of the resources in the play.

Oil and Gas Supply Module

Figure 13. Oil and Gas Supply Module Structure



Subsequently, prices received from NGTDM and endogenously determined costs adjusted to reflect technological progress are utilized to calculate the economic profitability (or lack thereof) for the play. If the play is profitable, drilling occurs according to an assumed schedule, which is adjusted annually to account for technological improvements, as well as varying economic conditions. This drilling results in reserve additions, the quantities of which are directly related to the EURs for the wells in that play. Given these reserve additions, reserve levels and expected production–to–reserves (P/R) ratios are calculated at both the OGSM and the NGTDM region level. The resultant values are aggregated with similar values from the conventional onshore and offshore submodules. The aggregate P/R ratios and reserve levels are then passed to NGTDM, which determines the prices and production for the following year through market equilibration.

Offshore Supply Submodule

This submodule uses a field-based engineering approach to represent the exploration and development of U.S. offshore oil and natural gas resources. The submodule simulates the economic decision-making at each stage of development from frontier areas to post-mature areas. Offshore resources are divided into 3 categories:

- **Undiscovered Fields.** The number, location, and size of the undiscovered fields are based on the MMS's 2006 hydrocarbon resource assessment.
- **Discovered, Undeveloped Fields.** Any discovery that has been announced but is not currently producing is evaluated in this component of the model. The first production year is an input and is based on announced plans and expectations.

- **Producing Fields.** The fields in this category have wells that have produced oil and/or gas through the year prior to the AEO projection. The production volumes are from the Minerals Management Service (MMS) database.

Resource and economic calculations are performed at an evaluation unit basis. An evaluation unit is defined as the area within a planning area that falls into a specific water depth category. Planning areas are the Western Gulf of Mexico (GOM), Central GOM, Eastern GOM, Pacific, and Atlantic. There are six water depth categories: 0-200 meters, 200-400 meters, 400-800 meters, 800-1600 meters, 1600-2400 meters, and greater than 2400 meters.

Supply curves for crude oil and natural gas are generated for three offshore regions: Pacific, Atlantic, and GOM. Crude oil production includes lease condensate. Natural gas production accounts for both nonassociated gas and associated-dissolved gas. The model is responsive to changes in oil and natural gas prices, royalty relief assumptions, oil and natural gas resource base, and technological improvements affecting exploration and development.

Alaska Oil and Gas Submodule

This submodule projects the crude oil and natural gas produced in Alaska. The Alaskan oil submodule is divided into three sections: new field discoveries, development projects, and producing fields. Oil transportation costs to lower 48 facilities are used in conjunction with the relevant market price of oil to calculate the estimated net price received at the wellhead, sometimes called the netback price. A discounted cash flow method is used to determine the economic viability of each project at the netback price.

Alaskan oil supplies are modeled on the basis of discrete projects, in contrast to the onshore lower 48 conventional oil and gas supplies, which are modeled on an aggregate level. The continuation of the exploration and development of multiyear projects, as well as the discovery of new fields, is dependent on profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and developmental projects, historical production patterns, and announced plans for currently producing fields.

- Alaskan gas production is set separately for any gas targeted to flow through a pipeline to the lower 48 States and gas produced for consumption in the State and for export to Japan. The latter is set based on a projection of Alaskan consumption in the NGTDM and an exogenous specification of exports. North Slope production for the pipeline is dependent on construction of the pipeline, set to commence if the lower 48 average wellhead price is maintained at a level exceeding the established comparable cost of delivery to the lower 48 States.

Natural Gas Transmission and Distribution Module

Natural Gas Transmission And Distribution Module

The NGTDM of NEMS represents the natural gas market and determines regional market–clearing prices for natural gas supplies and for end–use consumption, given the information passed from other NEMS modules (Figure 14). A transmission and distribution network (Figure 15), composed of nodes and arcs, is used to simulate the interregional flow and pricing of gas in the contiguous United States and Canada in both the peak (December through March) and offpeak (April through November) period. This network is a simplified representation of the physical natural gas pipeline system and establishes the possible interregional flows and associated prices as gas moves from supply sources to end users.

Flows are further represented by establishing arcs from transshipment nodes to each demand sector represented in an NGTDM region (residential, commercial, industrial, electric generators, and transportation). Mexican exports and net storage injections in the offpeak period are also represented as flow exiting a transshipment node. Similarly, arcs are also established from supply points into a transshipment node. Each transshipment node can have one or more entering arcs from each supply source represented: U.S. or Canadian onshore or U.S. offshore production, liquefied natural gas imports, supplemental gas production, gas produced in Alaska and transported via pipeline, Mexican imports, or net storage withdrawals in the region in the peak period. Most of the types of supply listed above are set independently of current year prices and before NGTDM determines a market equilibrium solution.

Only the onshore and offshore lower 48 U.S. and Western Canadian Sedimentary Basin production, along with net storage withdrawals, are represented by short–term supply curves and set dynamically during the NGTDM solution process. The construction of natural gas pipelines from Alaska and Canada's MacKenzie Delta are triggered when market prices exceed estimated project costs. The flow of gas during the peak period is used to establish interregional pipeline and storage capacity requirements and the associated expansion. These capacity levels provide an upper limit for the flow during the offpeak period.

Arcs between transshipment nodes, from the transshipment nodes to end–use sectors, and from supply sources to transshipment nodes are assigned tariffs. The tariffs along interregional arcs reflect reservation (represented with volume dependent curves) and usage fees and are established in the pipeline tariff submodule. The tariffs on arcs to end–use sectors represent the interstate pipeline tariffs in the region, intrastate pipeline tariffs, and distributor markups set in the distributor tariff submodule. Tariffs on arcs from supply sources represent gathering charges or other differentials between the price at the supply source and the regional market hub. The tariff associated with injecting, storing, and withdrawing from storage is assigned to the arc representing net storage withdrawals in the peak period. During the primary solution process in the interstate transmission submodule, the tariffs along an interregional arc are added to the price at the source node to arrive at a price for the gas along the arc right before it reaches its destination node.

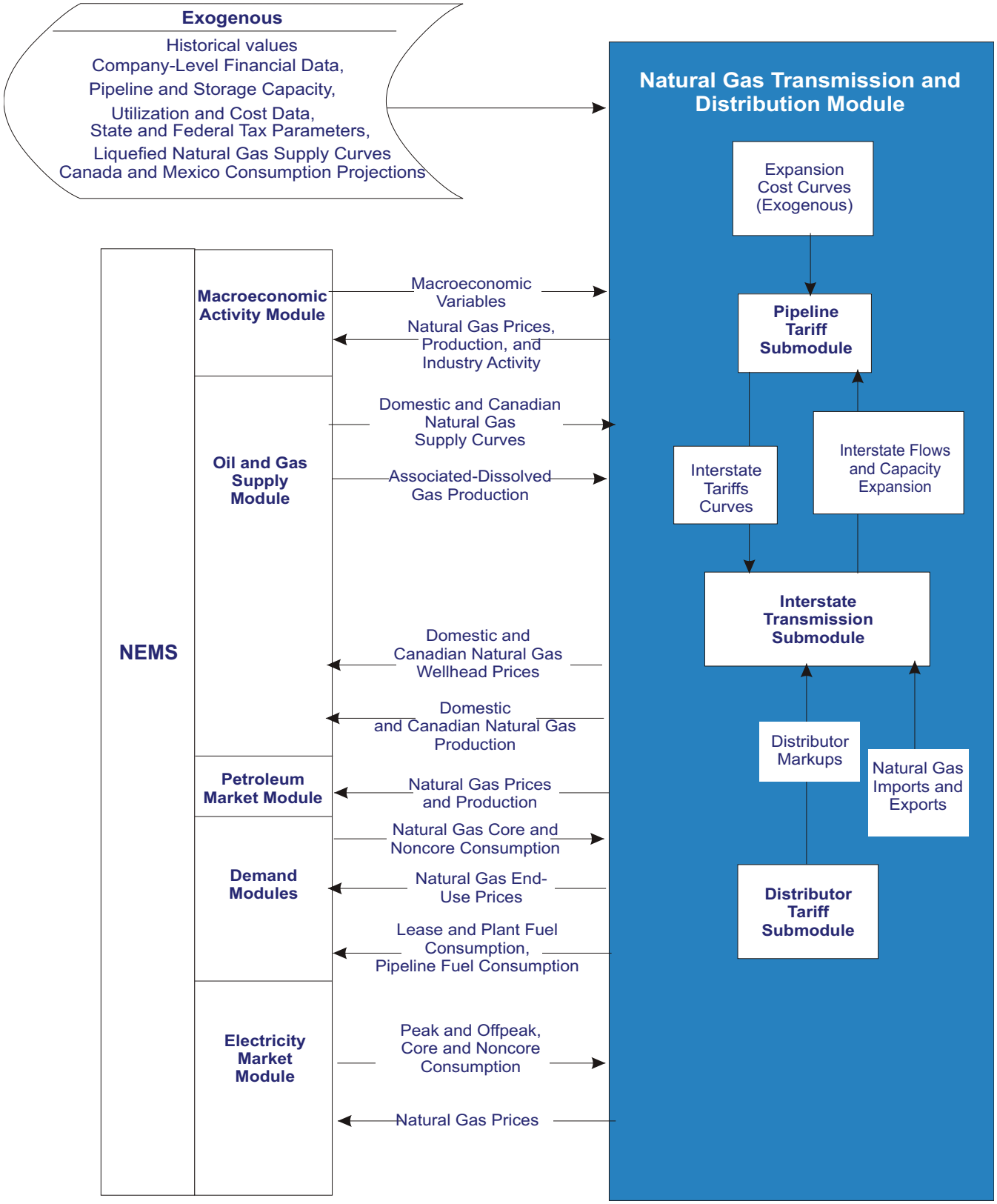
Interstate Transmission Submodule

The interstate transmission submodule (ITS) is the main integrating module of NGTDM. One of its major functions is to simulate the natural gas price determination process. ITS brings together the major economic factors that influence regional natural gas trade on a seasonal basis in the United States, the balancing of the demand for and the domestic supply of natural gas, including competition from imported natural gas. These are examined in combination with the relative prices associated with moving the gas from the producer to the end user where and when (peak versus offpeak) it is

NGTDM Outputs	Inputs from NEMS	Exogenous Inputs
Natural gas delivered prices Domestic and Canadian natural gas wellhead prices Domestic natural gas production Mexican and liquefied natural gas imports and exports Canadian natural gas imports and production Lease and plant fuel consumption Pipeline and distribution tariffs Interregional natural gas flows Storage and pipeline capacity expansion Supplemental gas production	Natural gas demands Domestic and Canadian natural gas supply curves Macroeconomic variables Associated-dissolved natural gas production	Historical consumption and flow patterns Historical supplies Pipeline company-level financial data Pipeline and storage capacity and utilization data Historical end-use citygate, and wellhead prices State and Federal tax parameters Pipeline and storage expansion cost data Liquefied natural gas supply curves Canada and Mexico consumption projections

Natural Gas Transmission And Distribution Module

Figure 14. Natural Gas Transmission and Distribution Module Structure



needed. In the process, ITS simulates the decision–making process for expanding pipeline and/or seasonal storage capacity in the U.S. gas market, determining the amount of pipeline and storage capacity to be added between or within regions in NGTDM. Storage serves as the primary link between the two seasonal periods represented.

ITS employs an iterative heuristic algorithm, along with an acyclic hierarchical representation of the primary arcs in the network, to establish a market equilibrium solution. Given the consumption levels from other NEMS modules, the basic process followed by ITS involves first establishing the backward flow of natural gas in each period from the consumers, through the network, to the producers, based primarily on the relative prices offered for the gas from the previous ITS iteration. This process is performed for the peak period first since the net withdrawals from storage during the peak period will establish the net injections during the offpeak period. Second, using the model's supply curves, wellhead and import prices are set corresponding to the desired production volumes. Also, using the pipeline and storage tariffs from the pipeline tariff submodule, pipeline and storage tariffs are set corresponding to the associated flow of gas, as determined in the first step. These prices are then translated from the producers, back through the network, to the city gate and the end users, by adding the appropriate tariffs along the way. A regional storage tariff is added to the price of gas injected into storage in the offpeak to arrive at the price of the gas when withdrawn in the peak period. This process is then repeated until the solution has converged. Finally, delivered prices are derived for residential, commercial, and transportation customers, as well as for both core and noncore industrial and electric generation sectors using the distributor tariffs provided by the distributor tariff submodule.

Pipeline Tariff Submodule

The pipeline tariff submodule (PTS) provides usage fees and volume dependent curves for computing unitized reservation fees (or tariffs) for interstate transportation and storage services within the ITS. These curves extend beyond current capacity levels and relate incremental pipeline or storage capacity expansion to corresponding estimated rates. The underlying basis for each tariff curve in the model is a projection of the associated regulated revenue requirement. Econometrically estimated equations within a general accounting framework are used to track costs and compute revenue requirements associated with both reservation and usage fees under current rate design and regulatory scenarios. Other than an assortment of macroeconomic indicators, the primary input to PTS from other modules in NEMS is pipeline and storage capacity utilization and expansion in the previous projection year.

Once an expansion is projected to occur, PTS calculates the resulting impact on the revenue requirement. PTS assumes rolled–in (or average), not incremental, rates for new capacity. The pipeline tariff curves generated by PTS are used within the ITS when determining the relative cost of purchasing and moving gas from one source versus another in the peak and offpeak seasons.

Distributor Tariff Submodule

The distributor tariff submodule (DTS) sets distributor markups charged by local distribution companies for the distribution of natural gas from the city gate to the end user. For those that do not typically purchase gas through a local distribution company, this markup represents the differential between the citygate and delivered price. End–use distribution service is distinguished within the DTS by sector (residential, commercial, industrial, electric generators, and transportation), season (peak and offpeak), and service type (core and noncore).

Distributor tariffs for all but the transportation sector are set using econometrically estimated equations. The natural gas vehicle sector markups are calculated separately for fleet and personal vehicles and account for distribution to delivery stations, retail markups, and federal and state motor fuels taxes.

Natural Gas Imports and Exports

Liquefied natural gas imports for the U.S., Canada, and Baja, Mexico are set at the beginning of each NEMS iteration within the NGTDM by evaluating seasonal east and west supply curves, based on outputs from EIA's International Natural Gas Model, at associated regasification tailgate prices set in the previous NEMS iteration. A sharing algorithm is used to allocate the resulting import volumes to particular regions. LNG exports to Japan from Alaska are set exogenously by the OGSM.

The Mexico model is largely based on exogenously specified assumptions about consumption and production growth rates and LNG import levels. For the most part, natural gas imports from Mexico are set exogenously for each of the three border crossing points with

Figure 15. Natural Gas Transmission and Distribution Module Network



the United States, with the exception of any gas that is imported into Baja, Mexico in liquid form only to be exported to the United States. Exports to Mexico from the United States are established before the NGTDM equilibrates and represent the required level to balance the assumed consumption in (and exports from) Mexico against domestic production and LNG imports. The production levels are also largely assumption based, but are set to vary with changes in the expected wellhead price in the United States.

A node for east and west Canada is included in the NGTDM equilibration network, as well as seven border crossings into the United States. The model includes a representation/accounting of the U.S. border crossing pipeline capacity, east and west seasonal storage transfers, east and west consumption, east and west LNG imports, eastern production, conventional/tight sands production in the west, and coalbed/shale production. Imports from the United States, conventional production in eastern Canada, and base level natural gas consumption (which varies with the world oil price) are set exogenously. Conventional/tight sands production in the west is set using a supply curve from the OGSM. Coalbed and shale gas production are effectively based on an assumed production growth rate which is adjusted with realized prices.

Petroleum Market Module

Petroleum Market Module

The PMM represents domestic refinery operations and the marketing of liquid fuels to consumption regions. PMM solves for liquid fuel prices, crude oil and product import activity (in conjunction with the IEM and the OGSM), and domestic refinery capacity expansion and fuel consumption. The solution satisfies the demand for liquid fuels, incorporating the prices for raw material inputs, imported liquid fuels, capital investment, as well as the domestic production of crude oil, natural gas liquids, and other unconventional refinery inputs. The relationship of PMM to other NEMS modules is illustrated in Figure 16.

The PMM is a regional, linear programming formulation of the five Petroleum Administration for Defense Districts (PADDs) (Figure 17). For each region two distinct refinery are modeled. One is highly complex using over 40 different refinrry processes, while the second is defined as a simple refinery that provides marginal cost economics. Refining capacity is allowed to expand in each region, but the model does not distinguish between additions to existing refineries or the building of new facilities. Investment criteria are developed exogenously, although the decision to invest is endogenous.

PMM assumes that the petroleum refining and marketing industry is competitive. The market will move toward lower-cost refiners who have access to crude oil and markets. The selection of crude oils, refinery process utilization, and logistics (transportation) will adjust to minimize the overall cost of supplying the market with liquid fuels.

PMM's model formulation reflects the operation of domestic liquuid fuels. If demand is unusually high in one region, the price will increase, driving down demand and providing economic incentives for bringing supplies in from other regions, thus restoring the supply and demand balance.

Existing regulations concerning product types and specifications, the cost of environmental compliance, and Federal and State taxes are also modeled. PMM incorporates provisions from the Energy Independence and Security Act of 2007 (EISA2007) and the Energy Policy Act of 2005 (EPACT05). The costs of producing new formulations of gasoline and diesel fuel as a result of the CAAA90 are determined within the linear-programming representation by incorporating specifications and demands for these fuels.

PMM also includes the interaction between the domestic and international markets. Prior to AEO2009, PMM postulated entirely exogenous prices for oil on the international market (the world oil price). Subsequent AEOs include an International Energy Module (IEM) that estimates supply curves for imported crude oils and products based on, among other factors, U.S. participation in global trade of crude oil and liquid fuels.

Regions

PMM models U.S. crude oil refining capabilities based on the five PADDs which were established during World War II and are still used by EIA for data collection and analysis. The use of PADD data permits PMM to take full advantage of EIA's historical database and allows analysis within the same framework used by the petroleum industry.

PMM Outputs	Inputs from NEMS	Exogenous Inputs
Petroleum product prices	Petroleum product demand by sector	Processing unit operating parameters
Crude oil imports and exports	Domestic crude oil production	Processing unit capacities
Crude oil demand	World oil price	Product specifications
Petroleum product imports and exports	International crude oil supply curves	Operating costs
Refinery activity and fuel use	International product supply curves	Capital costs
Ethanol demand and price	International oxygenates supply curves	Transmission and distribution costs
Combined heat and power (CHP)	Natural gas prices	Federal and State taxes
Natural gas plant liquids production	Electricity prices	Agricultural feedstock quantities and costs
Processing gain	Natural glas production	CHP unit operating parameters
Capacity additions	Macroeconomic variables	CHP unit capacities
Capital expenditures	Biomass supply curves	
Revenues	Coal prices	

Figure 16. Petroleum Market Module Structure

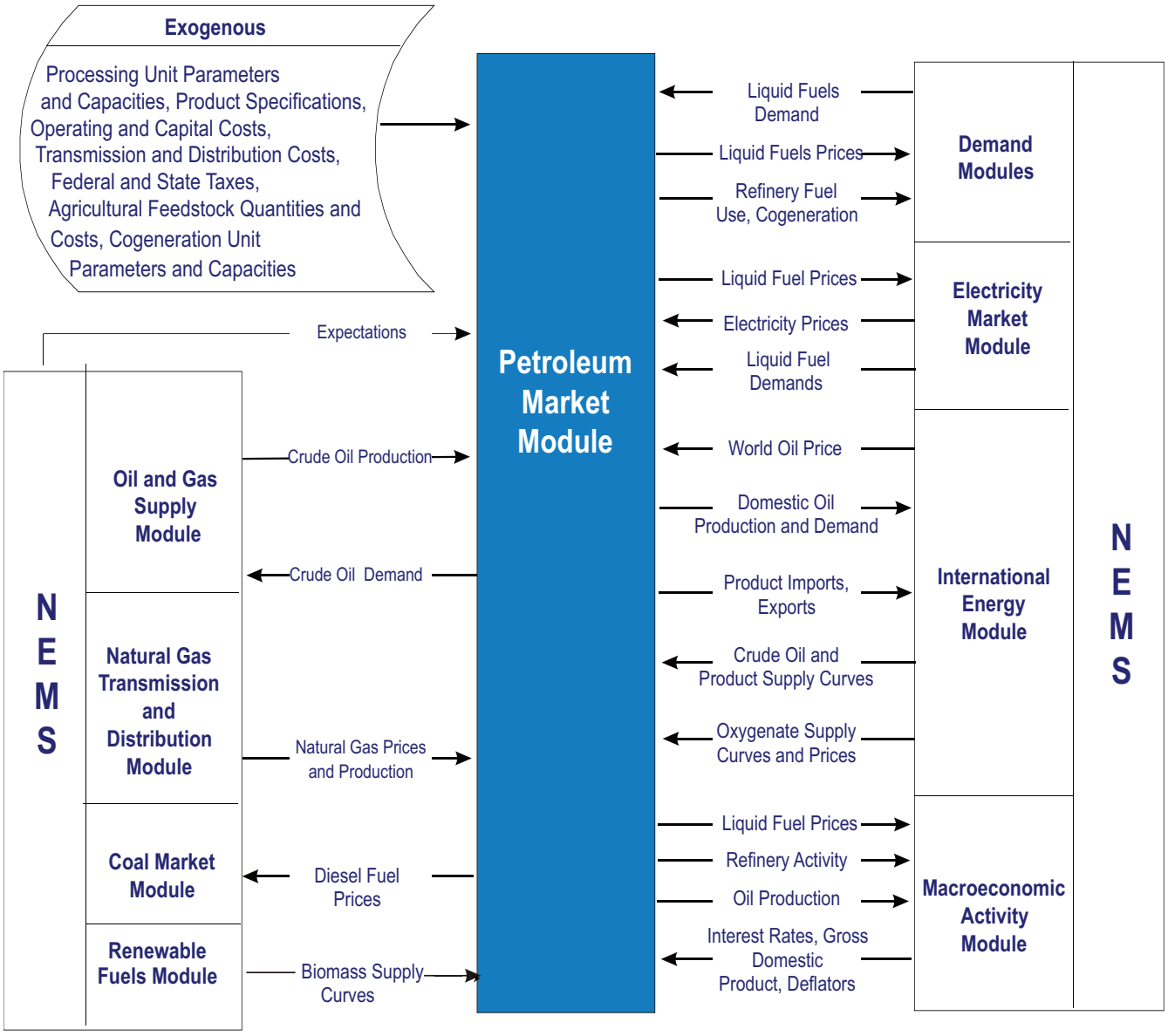
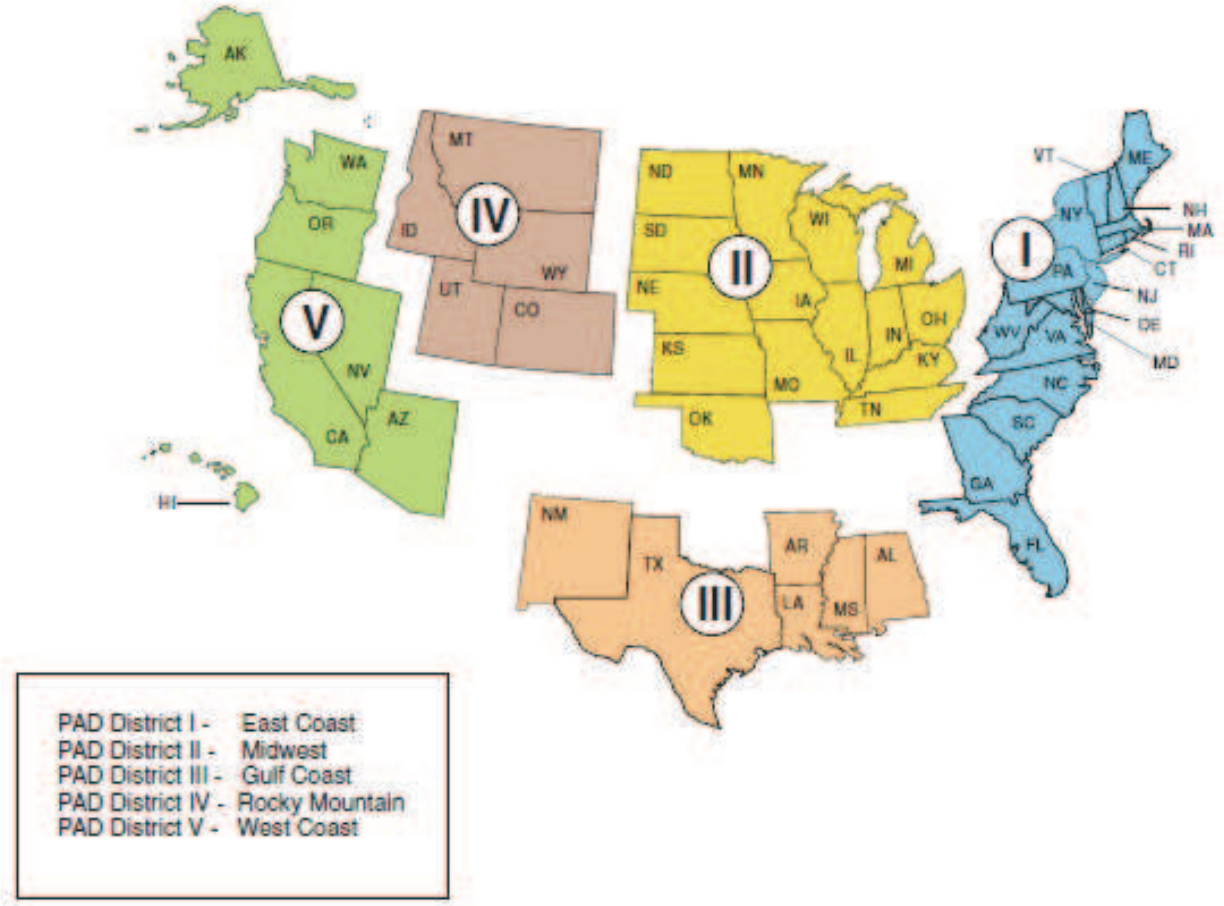


Figure 17. Petroleum Administration for Defense Districts



Product Categories

Product categories, specifications and recipe blends modeled in PMM include the following:

Liquid Fuels Modeled in PMM

Motor gasoline: conventional (oxygenated and non-oxygentated), reformulated, and California reformulated
Jet fuels: kerosene-based
Distillates: kerosene, heating oil, low sulfur (LSD) and ultra-low-sulfur (ULSD) highway diesel, distillate fuel oil, and distillate fuel from various non-crude feedstocks (coal, biomass, natural gas) via the Fischer-Tropsch process (BTL, CTL, GTL)
Alternative Fuel: Biofuels [including ethanol, biodiesel (methyl-ester), renewable diesel, biomass-to-liquids (BTL)], coal-to-liquids (CTL), gas-to-liquids (GTL).
Residual fuels: low sulfur and high sulfur residual fuel oil
Liquefied petroleum gas (LPG): a light-end mixture used for fuel in a wide range of sectors comprised primarily of propane
Natural gas plant:ethane, propane, iso and normal butane, and pentanes plus (natural gasoline)
Petrochemical feedstocks
Other: asphalt and road oil, still gas, (refinery fuel) petroleum coke, lubes and waxes, special naphthas

Fuel Use

PMM determines refinery fuel use by refining region for purchased electricity, natural gas, distillate fuel, residual fuel, liquefied petroleum gas, and other petroleum. The fuels (natural gas, petroleum, other gaseous fuels, and other) consumed within the refinery to generate electricity from CHP facilities are also determined.

Crude Oil Categories

Both domestic and imported crude oils are aggregated into five categories as defined by API gravity and sulfur content ranges. This aggregation of crude oil types allows PMM to account for changes in crude oil composition over time. A composite crude oil with the appropriate yields and qualities is developed for each category by averaging characteristics of foreign and domestic crude oil streams.

Refinery Processes

The following distinct processes are represented in the PMM:

1) Crude Oil Distillation
   a. Atmospheric Crude Unit
   b. Vacuum Crude Unit

2) Residual Oil Upgrading
   a. Coker - Delayed, fluid
   b. Thermal Cracker/Visbreaker
   c. Residuum Hydrocradker
   d. Solvent Deasphalting

3) Cracking
   a. Fluidized Catalytic Cracker
   b. Hydrocracker

4) Final Product Treating/Upgrading
   a. Traditional Hydrotreating
   b. Modern Hydrotreating
   c. Alkylation
   d. Jet Fuel Production
   e. Benzene Saturation
   f. Catalytic Reforming

5) Light End Treating
   a. Saturated Gas Plant
   b. Isomerization
   c. Dimerization/Polymerization
   d. C2-C5 Dehydrogenation

6) Non-Fuel Production
   a. Sulfur Plant
   b. Methanol Production
   c. Oxgenate Production
   d. Lube and Wax Production
   e. Steam/Power Generation
   f. Hydrogen Production
   g. Aromatics Production

7) Specialty Unit Operations
   a. Olefins to Gasoline/Diesel
   b. Methanol to Olefins

8) Merchant Facilities
   a. Coal/Gas/Biomass to Liquids
   b. Natural Gas Plant
   c. Ethanol Production
   d. Biodiesel Plant

Natural Gas Plants

Natural gas plant liquids (ethane, propane, normal butane, isobutane, and natural gasoline) produced from natural gas processing plants are modeled in PMM. Their production levels are based on the projected natural gas supply and historical liquids yields from various natural gas sources. These products move directly into the market to meet demand (e.g., for fuel or petrochemical feedstocks) or are inputs to the refinery.

Biofuels

PMM contains submodules which provide regional supplies and prices for biofuels: ethanol (conventional/corn, advanced, cellulosic) and various forms of biomass-based diesel: FAME (methyl ester), biomass-to-liquid (Fisher-Tropsch), and renewable ("green") diesel (hydrogenation of vegetable oils or fats). Ethanol is assumed to be blended either at 10 percent into gasoline (conventional or reformulated) or as E85. Food feedstock supply curves (corn, soybean oil, etc.) are updated to USDA baseline projections; biomass feedstocks are drawn from the same supply curves that also supply biomass fuel to renewable power generation within the Renewable Fuels Module of NEMS. The merchant processing units which generate the biofuels supplies sum these feedstock costs with other cost inputs (e.g., capital, operating). A major driving force behind the production of these biofuels is the Renewable Fuels Standard under EISA2007. Details on the market penetration of the advanced biofuels production capacity (such as cellulosic ethanol and BTL) which are not yet commercialized can be found in the PMM documentation.

End-Use Markups

The linear programming portion of the model provides unit prices of products sold in the refinery regions (refinery gate) and in the demand regions (wholesale). End use markups are added to produce a retail price for each of the Census Divisions. The mark ups are based on an average of historical markups, defined as the difference between the end-use prices by sector and the corresponding wholesale price for that product. The average is calculated using data from 2000 to the present. Because of the lack of any consistent trend in the historical end-use markups, the markups remain at the historical average level over the projection period.

State and Federal taxes are also added to transportation fuel prices to determine final end-use prices. Previous tax trend analysis indicates that state taxes increase at the rate of inflation, while Federal taxes do not. In PMM, therefore state taxes are held constant in real terms throughout the projection while Federal taxes are felated at the rate of inflation.[18]

Gasoline Types

Motor vehicle fuel in PMM is categorized into four gasoline blends (conventional, oxygenated conventional, reformulated, and California reformulated) and also E85. While federal law does not mandate gasoline to be oxygenated, all gasoline complying with the Federal reformulated gasoline program is assumed to contain 10 percent ethanol, while conventional gasoline may be "clear" (no ethanol) or used as E10. As the mandate for biofuels grows under the Renewable Fuels Standard, the proportion of conventional gasoline that is E10 also generally grows. California reformulated motor gasoline is assumed to contain 5.7% ethanol in 2009 and 10 percent thereafter in line with its approval of the use of California's Phase 3 reformulated gasoline.

EIA defines E85 as a gasoline type but is treated as a separate fuel in PMM. The transportation module in NEMS provides PMM with a flex fuel vehicle (FFV) demand, and PMM computes a supply curve for E85. This curve incorporates E85 infrastructure and station costs, as well as a logit relationship between the E85 station availability and demand of E85. Infrastructure costs dictate that the E85 supplies emerge in the Midwest first, followed by an expansion to the coasts.

Ultra–Low–Sulfur Diesel

By definition, Ultra Low Sulfur Diesel (ULSD) is highway diesel fuel that contains no more than 15 ppm sulfur at the pump. As of June 2006, 80 percent of all highway diesel produced or imported into the United States was required to be ULSD, while the remaining 20 percent contained a maximum of 500 parts per million. By December 1, 2010 all highway fuel sold at the pump will be required to be ULSD. Major assumptions related to the ULSD rule are as follows:

- Highway diesel at the refinery gate will contain a maximum of 7-ppm sulfur. Although sulfur content is limited to 15 ppm at the pump, there is a general consensus that refineries will need to produce diesel below 10 ppm sulfur in order to allow for contamination during the distribution process.

- Demand for highway grade diesel, both 500 and 15 ppm combined, is assumed to be equivalent to the total transportation distillate demand. Historically, highway grade diesel supplied has nearly matched total transportation distillate sales, although some highway grade

18 http://www.eia.doe.gov/oiaf/archive/aeo07/leg_reg.html.

diesel has gone to non-transportation uses such as construction and agriculture.

Gas, Coal and Biomass to Liquids

Natural gas, coal, and biomass conversion to liquid fuels is modeled in the PMM based on a three step process known as indirect liquefaction. This process is sometimes called Fischer-Tropsch (FT) liquefaction after the inventors of the second step.

The liquid fuels produced include four separate products: FT light naphtha, FT heavy naphtha, FT kerosene, and FT diesel. The FT designation is used to distinguish these liquid fuels from their petroleum counterparts. This is necessary due to the different physical and chemical properties of the FT fuels. For example, FT diesel has a typical cetane rating of approximately 70-75 while that of petroleum diesel is typically much lower (about 40). In addition, the above production methods have differing impacts with regard to current and potential legislation, particularly RFS and CO2.

Coal Market Module

Coal Market Module

The coal market module (CMM) represents the mining, transportation, and pricing of coal, subject to end-use demand. Coal supplies are differentiated by thermal grade, sulfur content, and mining method (underground and surface). CMM also determines the minimum cost pattern of coal supply to meet exogenously defined U.S. coal export demands as a part of the world coal market. Coal distribution, from supply region to demand region, is projected on a cost-minimizing basis. The domestic production and distribution of coal is projected for 14 demand regions and 14 supply regions (Figures 18 and 19).

The CMM components are solved simultaneously. The sequence of solution among components can be summarized as follows. Coal supply curves are produced by the coal production submodule and input to the coal distribution submodule. Given the coal supply curves, distribution costs, and coal demands, the coal distribution submodule projects delivered coal prices. The module is iterated to convergence with respect to equilibrium prices to all demand sectors. The structure of the CMM is shown in Figure 20.

Coal Production Submodule

This submodule produces annual coal supply curves, relating annual production to minemouth prices. The supply curves are constructed from an econometric analysis of prices as a function of productive capacity, capacity utilization, productivity, and various factor input costs. A separate supply curve is provided for surface and underground mining for all significant production by coal thermal grade (metallurgical, bituminous, subbituminous and lignite), and sulfur level in each supply region. Each supply curve is assigned a unique heat, sulfur, and mercury content, and carbon dioxide emissions factor. Constructing curves for the coal types available in each region yields a total of 40 curves that are used as inputs to the coal distribution submodule. Supply curves are updated for each year in the projection period. Coal supply curves are shared with both the EMM and the PMM. For detailed assumptions, please see the Assumptions to the Annual Energy Outlook updated each year with the release of the AEO.

Coal Distribution Submodule: Domestic Component

The coal distribution submodule is a linear program that determines the least-cost supplies of coal for a given set of coal demands by demand region and sector, accounting for transportation costs from the different supply curves, heat and sulfur content, and existing coal supply contracts. Existing supply contracts between coal producers and electricity generators are incorporated in the model as minimum flows for supply curves to coal demand regions. Depending on the specific scenario, coal distribution may also be affected by any restrictions on sulfur dioxide, mercury, or carbon dioxide emissions.

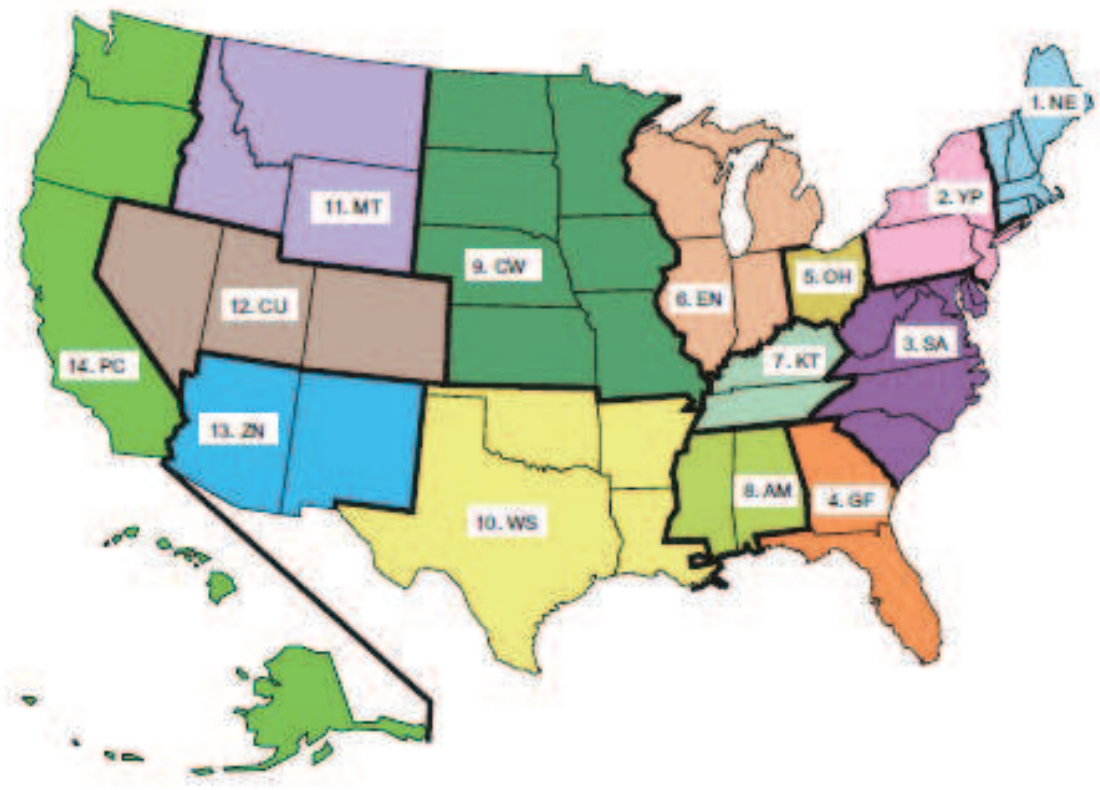
Coal transportation costs are simulated using interregional coal transportation costs derived by subtracting reported minemouth costs for each supply curve from reported delivered costs for each demand type in each demand region. For the electricity sector, higher transportation costs are assumed for market expansion in certain supply and demand region combinations. Transportation rates are modified over time using econometrically based multipliers which considers the impact of changing productivity and equipment costs. When diesel fuel prices are sufficiently high, a fuel surcharge is also added to the transportation costs.

Coal Distribution Submodule: International Component

The international component of the coal distribution submodule projects quantities of coal imported and exported from the United States. The quantities are determined within a world trade context, based on assumed characteristics of foreign coal supply and demand. The component disaggregates coal into 17 export regions and 20 import regions, as shown inTable 13. The supply and demand components of world coal trade are

CMM Outputs	Inputs from NEMS	Exogenous Inputs
Coal production and distribution Minemouth coal prices End-use coal prices U.S. coal exports and imports Transportation rates Coal quality by source, destination, and end-use sector World coal flows	Coal demand Interest rates Price indices and deflators Diesel fuel prices Electricity prices	Base year production, productive capacity, capacity utilization, prices, and coal quality parameters Contract quantities Labor productivity Labor costs Domestic transportation costs International transportation costs International supply curves International coal import demands

Figure 18. Coal Market Module Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. SA	WV,MD,DC,DE,VA,NC,SC
4. GF	GA,FL
5. OH	OH
6. EN	IN,IL,MI,WI
7. KT	KY,TN

Region Code	Region Content
8. AM	AL,MS
9. CW	MN,IA,ND,SD,NE,MO,KS
10. WS	TX,LA,OK,AR
11. MT	MT,WY,ID
12. CU	CO,UT,NV
13. ZN	AZ,NM
14. PC	AK,HI,WA,OR,CA

segmented into two separate markets: 1) coking coal, which is used for the production of coke for the steelmaking process; and 2) steam coal, which is primarily consumed in the electricity and industrial sectors.

The international component is solved as part of the linear program that optimizes U.S. coal supply. It determines world coal trade distribution by minimizing overall costs for coal, subject to coal supply prices in the United States and other coal exporting regions plus transportation costs. The component also incorporates supply diversity constraints that reflect the observed tendency of coal-importing countries to avoid excessive dependence upon one source of supply, even at a somewhat higher cost.

Figure 19. Coal Market Module Supply Regions

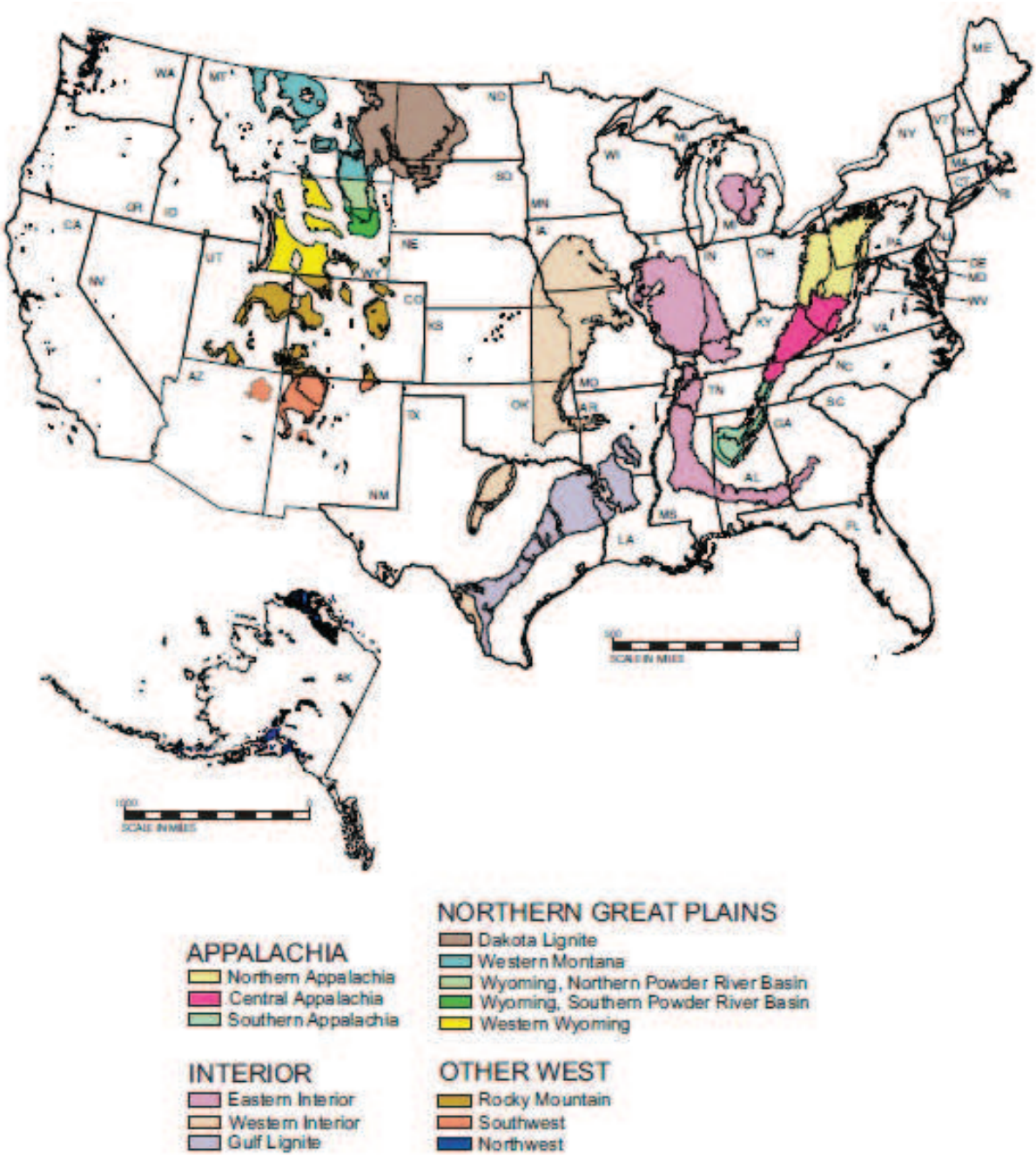
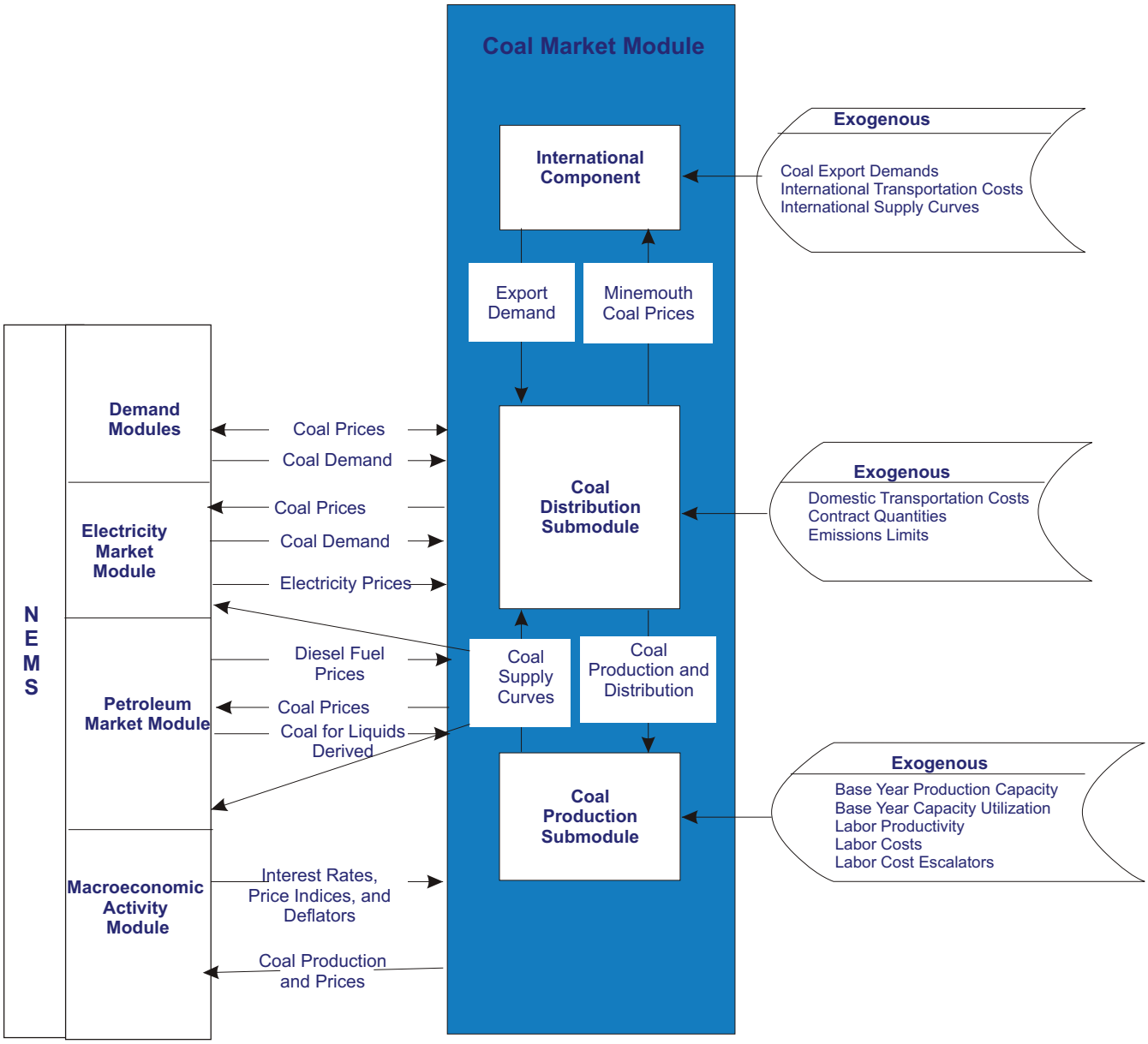


Table 13. Coal Export Component

Coal Export Regions	Coal Import Regions
U.S. East Coast	U.S. East Coast
U.S. Gulf Coast	U.S. Gulf Coast
U.S. Southwest and West	U.S. Northern Interior
U.S. Northern Interior	U.S. Noncontiguous
U.S. Noncontiguous	Eastern Canada
Australia	Interior Canada
Western Canada	Scandinavia
Interior Canada	United Kingdom and Ireland
Southern Africa	Germany and Austria
Poland	Other Northwestern Europe
Eurasia-exports to Europe	Iberia
Eurasia-exports to Asia	Italy
China	Mediterranean and Eastern Europe
Colombia	Mexico
Indonesia	South America
Venezuela	Japan
Vietnam	East Asia
	China and Hong Kong
	ASEAN (Association of Southeast Asian Nations)
	India and South Asia

Coal Market Module

Figure 20. Coal Market Module Structure



Appendix

Appendix Bibliography

The National Energy Modeling System is documented in a series of model documentation reports, available on the EIA Web site at http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model documentation or by contacting the National Energy Information Center (202/586-8800).

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DOE/EIA-M062(2011)

Model Documentation

Natural Gas Transmission and Distribution Module of the National Energy Modeling System

February 2012

Office of Petroleum, Gas, and Biofuels Analysis
U.S. Energy Information Administration
U.S. Department of Energy
Washington, DC 20585

This report was prepared by the U.S. Energy Information Administration, the independent statistical and analytical agency within the Department of Energy. The information contained herein should not be construed as advocating or reflecting any policy position of the Department of Energy or any other organization.

Contact Information

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This report documents the archived version of the NGTDM that was used to produce the natural gas forecasts presented in the *Annual Energy Outlook 2011*, (DOE/EIA-0383(2011). The purpose of this report is to provide a reference document for model analysts, users, and the public that defines the objectives of the model, describes its basic approach, and provides detail on the methodology employed.

The model documentation is updated annually to reflect significant model methodology and software changes that take place as the model develops. The next version of the documentation is planned to be released in the first quarter of 2012.

Update Information

This edition of the model documentation of the Natural Gas Transmission and Distribution Module (NGTDM) reflects changes made to the module over the past year for the *Annual Energy Outlook 2011*. Aside from general data and parameter updates, the notable changes include the following:

- Reestimated equations for distributor and pipeline tariffs.
- Updated coalbed and shale undiscovered resource assumptions in Canada.
- Moved representation of conventional and tight natural gas production in Western Canada from the Oil and Gas Supply Module to the NGTDM.

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Abbreviations and Acronyms

AEO	Annual Energy Outlook
Bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
BTU	British Thermal Unit
DTS	Distributor Tariff Submodule
EMM	Electricity Market Module
GAMS	Gas Analysis Modeling System
IFFS	Integrated Future Forecasting System
ITS	Interstate Transmission Submodule
MEFS	Mid-term Energy Forecasting System
MMBTU	Million British thermal units
Mcf	Thousand cubic feet
MMcf	Million cubic feet
MMcfd	Million cubic feet per day
MMBBL	Million barrels
NEMS	National Energy Modeling System
NGA	Natural Gas Annual
NGM	Natural Gas Monthly
NGTDM	Natural Gas Transmission and Distribution Module
OGSM	Oil and Gas Supply Module
PIES	Project Independence Evaluation System
PMM	Petroleum Market Module
PTS	Pipeline Tariff Submodule
STEO	Short-Term Energy Outlook
Tcf	Trillion cubic feet
WCSB	Western Canadian Sedimentary Basin

1. Background/Overview

The Natural Gas Transmission and Distribution Module (NGTDM) is the component of the National Energy Modeling System (NEMS) that is used to represent the U.S. domestic natural gas transmission and distribution system. NEMS was developed by the former Office of Integrated Analysis and Forecasting of the U.S. Energy Information Administration (EIA) and is the third in a series of computer-based, midterm energy modeling systems used since 1974 by the EIA and its predecessor, the Federal Energy Administration, to analyze and project U.S. domestic energy-economy markets. From 1982 through 1993, the Intermediate Future Forecasting System (IFFS) was used by the EIA for its integrated analyses. Prior to 1982, the Midterm Energy Forecasting System (MEFS), an extension of the simpler Project Independence Evaluation System (PIES), was employed. NEMS was developed to enhance and update EIA's modeling capability. Greater structural detail in NEMS permits the analysis of a broader range of energy issues. While NEMS was initially developed in 1992 the model is updated each year, from simple historical data updates to complete replacements of submodules.

The time horizon of NEMS is the midterm period that extends approximately 25 years to year 2035. In order to represent the regional differences in energy markets, the component modules of NEMS function at regional levels appropriate for the markets represented, with subsequent aggregation/disaggregation to the Census Division level for reporting purposes. The projections in NEMS are developed assuming that energy markets are in equilibrium[1] using a recursive price adjustment mechanism.[2]. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for the economic competition between the various fuels and sources. NEMS is organized and implemented as a modular system.[3] The NEMS modules represent each of the fuel supply markets, conversion sectors (e.g., refineries and power generation), and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. A routine was also added to the system that simulates a carbon emissions cap and trade system with annual fees to limit carbon emissions from energy-related fuel combustion. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, Census Division, and end-use sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data such as economic activity, domestic production activity, and international petroleum supply availability.

The integrating routine of NEMS controls the execution of each of the component modules. The modular design provides the capability to execute modules individually, thus allowing independent analysis with, as well as development of, individual modules. This modularity allows the use of the methodology and level of detail most appropriate for each energy sector. Each forecasting year, NEMS solves by iteratively calling each module in sequence (once in each NEMS iteration) until the delivered prices and quantities of each fuel in each region have

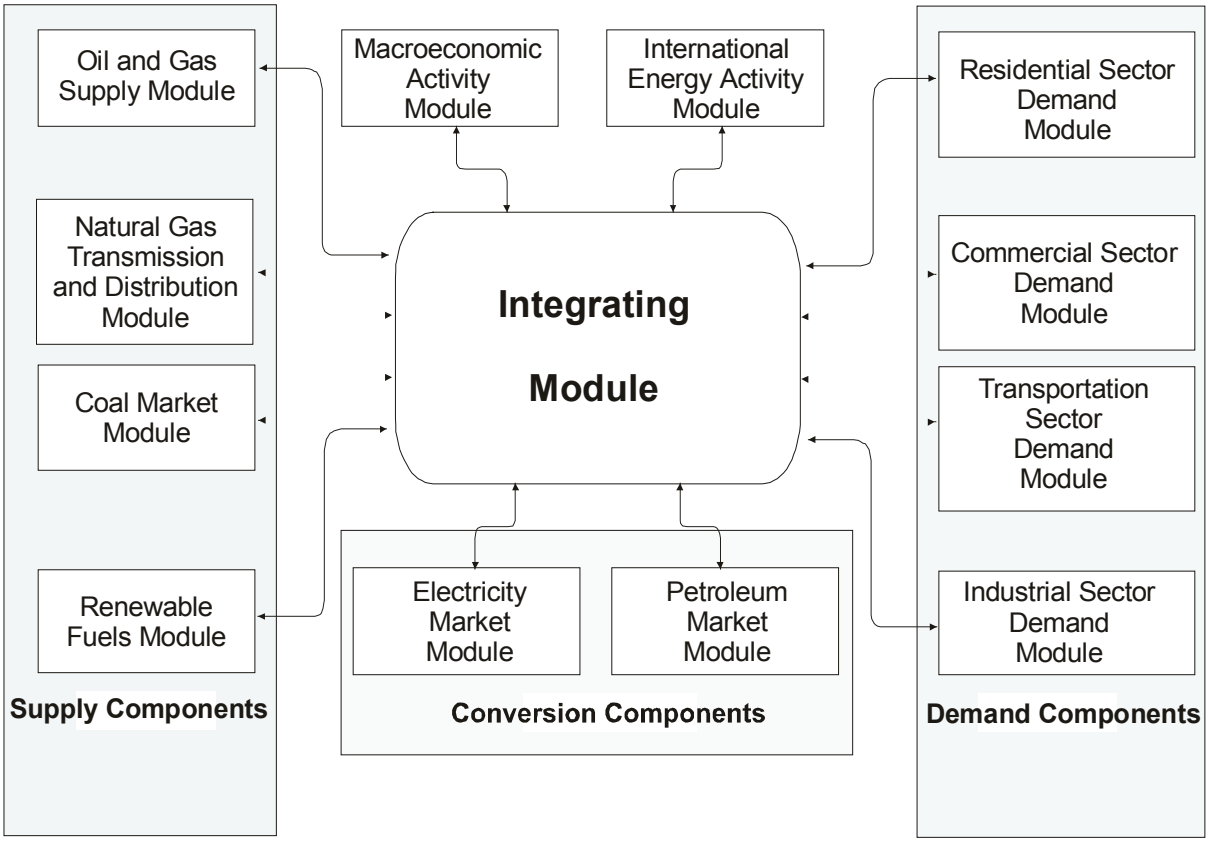
[1]Markets are said to be in equilibrium when the quantities demanded equal the quantities supplied at the same price; that is, at a price that sellers are willing to provide the commodity and consumers are willing to purchase the commodity.

[2]The central theme of the approach used is that supply and demand imbalances will eventually be rectified through an adjustment in prices that eliminates excess supply or demand.

[3]The NEMS is composed of 13 modules including a system integration routine.

converged within tolerance between the various modules, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Module solutions are reported annually through the midterm horizon. A schematic of the NEMS is provided in **Figure 1-1**, while a list of the associated model documentation reports is in Appendix C, including a report providing an overview of the whole system.

Figure 1-1. Schematic of the National Energy Modeling System



NGTDM Overview

The NGTDM module within the NEMS represents the transmission, distribution, and pricing of natural gas. Based on information received from other NEMS modules, the NGTDM also includes representations of the end-use demand for natural gas, the production of domestic natural gas, and the availability of natural gas traded on the international market. The NGTDM links natural gas suppliers (including importers) and consumers in the lower 48 States and across the Mexican and Canadian borders via a natural gas transmission and distribution network, while determining the flow of natural gas and the regional market clearing prices between suppliers and end-users. For two seasons of each forecast year, the NGTDM determines the production, flows, and prices of natural gas within an aggregate representation of the U.S./Canadian pipeline network, connecting domestic and foreign supply regions with 12 U.S. and 2 Canadian demand

regions. Since the NEMS operates on an annual (not a seasonal) basis, NGTDM results are generally passed to other NEMS modules as annual totals or quantity-weighted annual averages. Since the Electricity Market Module has a seasonal component, peak and off-peak[4] prices are also provided for natural gas to electric generators.

Natural gas pricing and flow patterns are derived by obtaining a market equilibrium across the three main elements of the natural gas market: the supply element, the demand element, and the transmission and distribution network that links them. The methodology employed allows for the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of primary pipeline and storage capacity expansion requirements. Key components of interstate pipeline tariffs are projected, along with distributor tariffs.

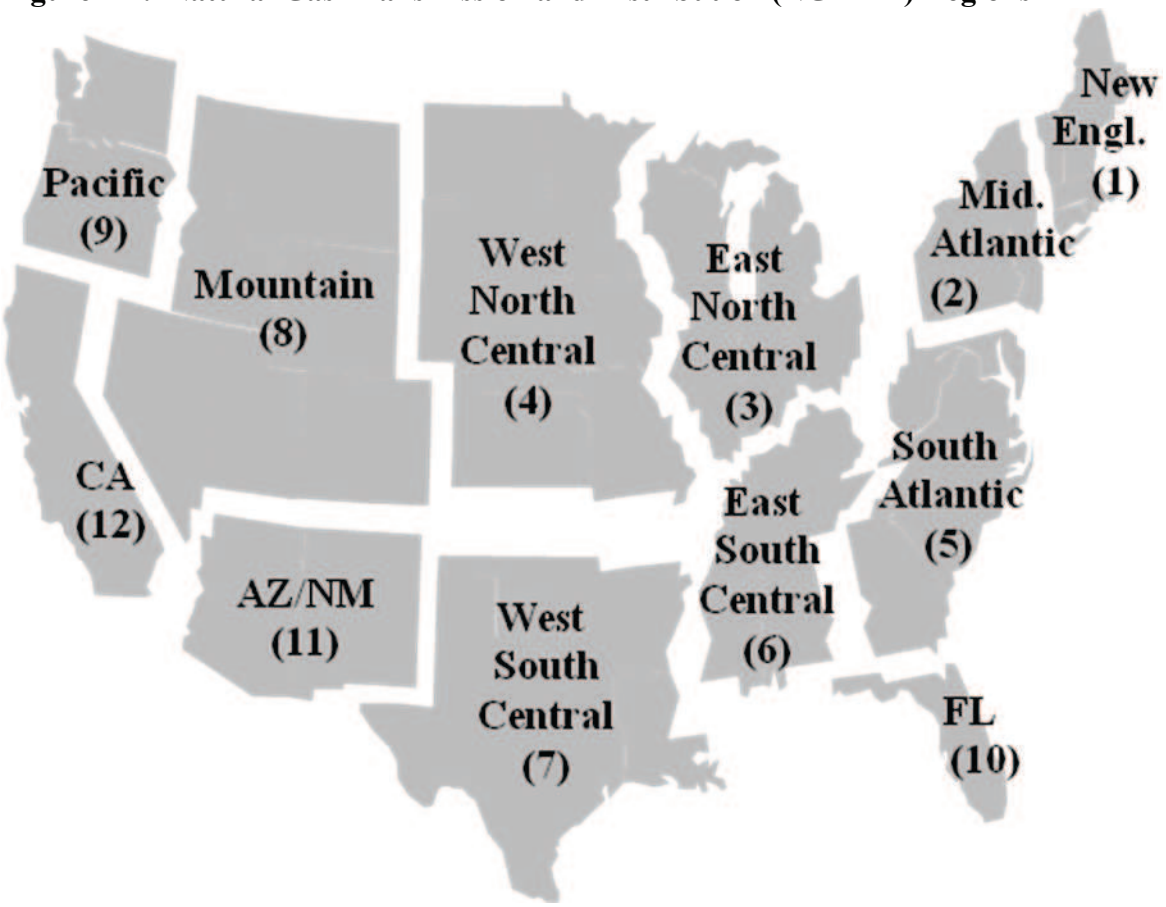
The lower-48 demand regions represented are the 12 NGTDM regions (**Figure 1-2**). These regions are an extension of the 9 Census Divisions, with Census Division 5 split into South Atlantic and Florida, Census Division 8 split into Mountain and Arizona/New Mexico, Census Division 9 split into California and Pacific, and Alaska and Hawaii handled independently. Within the U.S. regions, consumption is represented for five end-use sectors: residential, commercial, industrial, electric generation, and transportation (or natural gas vehicles), with the industrial and electric generator sectors further distinguished by core and noncore segments. One or more domestic supply region is represented in each of the 12 NGTDM regions. Canadian supply and demand are represented by two interconnected regions -- East Canada and West Canada -- which connect to the lower 48 regions via seven border crossing nodes. The demarcation of East and West Canada is at the Manitoba/Ontario border. In addition, the model accounts for the potential construction of a pipeline from Alaska to Alberta and one from the MacKenzie Delta to Alberta, if market prices are high enough to make the projects economic. The representation of the natural gas market in Canada is much less detailed than for the United States since the primary focus of the model is on the domestic U.S. market. Potential liquefied natural gas (LNG) imports into North America are modeled for each of the coastal regions represented in the model, including seven regions in the United States, a potential import point in the Bahamas, potential import points in eastern and western Canada, and in western Mexico (if destined for the United States).[5] Any LNG facilities in existence or under construction are represented in the model. However, the model does not project the construction of any additional facilities. Finally, LNG exports from Alaska's Nikiski plant are included, as well as three import/export border crossings at the Mexican border.

The module consists of three major components: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS). The ITS is the integrating submodule of the NGTDM. It simulates the natural gas price determination process by bringing together all major economic factors that influence regional natural gas trade in the United States, including pipeline and storage capacity expansion decisions. The Pipeline Tariff Submodule (PTS) generates a representation of tariffs for interstate transportation and storage services, both existing and expansions. The Distributor Tariff Submodule (DTS) generates markups for distribution services provided by local distribution companies and for

[4]The peak period covers the period from December through March; the off-peak period covers the remaining months.
[5]The LNG imports into Mexico to serve the Mexico market are set exogenously.

transmission services provided by intrastate pipeline companies. The modeling techniques employed are a heuristic/iterative process for the ITS, an accounting algorithm for the PTS, and a series of historically based and econometrically based equations for the DTS.

Figure 1-2. Natural Gas Transmission and Distribution (NGTDM) Regions



NGTDM Objectives

The purpose of the NGTDM is to derive natural gas delivered and wellhead prices, as well as flow patterns for movements of natural gas through the regional interstate network. Although the NEMS operates on an annual basis, the NGTDM was designed to be a two-season model, to better represent important features of the natural gas market. The prices and flow patterns are derived by obtaining a market equilibrium across the three main elements of the natural gas market: the supply element, the demand element, and the transmission and distribution network that links them. The representations of the key features of the transmission and distribution network are the focus of the various components of the NGTDM. These key modeling objectives/capabilities include:

- Represent interregional flows of gas and pipeline capacity constraints
- Represent regional and import supplies
- Determine the amount and the location of required additional pipeline and storage capacity on a regional basis, capturing the economic tradeoffs between pipeline and storage capacity additions
- Provide a peak/off-peak, or seasonal analysis capability
- Represent transmission and distribution service pricing

Overview of the Documentation Report

The archived version of the NGTDM that was used to produce the natural gas forecasts used in support of the *Annual Energy Outlook 2011*, DOE/EIA-0383(2011) is documented in this report. The purpose of this report is to provide a reference document for model analysts, users, and the public that defines the objectives of the model, describes its basic design, provides detail on the methodology employed, and describes the model inputs, outputs, and key assumptions. It is intended to fulfill the legal obligation of the EIA to provide adequate documentation in support of its models (Public Law 94-385, Section 57.b.2). Subsequent chapters of this report provide:

- A description of the interface between the NEMS and the NGTDM and the representation of demand and supply used in the module (Chapter 2)
- An overview of the solution methodology of the NGTDM (Chapter 3)
- The solution methodology for the Interstate Transmission Submodule (Chapter 4)
- The solution methodology for the Distributor Tariff Submodule (Chapter 5)
- The solution methodology for the Pipeline Tariff Submodule (Chapter 6)
- A description of module assumptions, inputs, and outputs (Chapter 7).

The archived version of the model is available through the National Energy Information Center (202-586-8800, infoctr@eia.doe.gov) and is identified as NEMS2011 (part of the National Energy Modeling System archive package as archived for the Annual Energy Outlook 2011, DOE/EIA-0383(2011)).

The document includes a number of appendices to support the material presented in the main body of the report. Appendix A presents the module abstract. Appendix B lists the major references used in developing the NGTDM. Appendix C lists the various NEMS Model Documentation Reports for the various modules that are mentioned throughout the NGTDM documentation. A mapping of equations presented in the documentation to the relevant subroutine in the code is provided in Appendix D. Appendix E provides a mapping between the variables that are assigned values through READ statements in the module and the data input files that are read. The input files contain detailed descriptions of the input data, including variable names, definitions, sources, units and derivations.[6] Appendix F documents the

[6]The NGTDM data files are available upon request by contacting Joe Benneche at Joseph.Benneche@eia.doe.gov or (202) 586-6132. Alternatively an archived version of the NEMS model (source code and data files) can be downloaded from ftp://ftp.eia.doe.gov/pub/forecasts/aeo.

derivation of all empirical estimations used in the NGTDM. Variable cross-reference tables are provided in Appendix G. Finally, Appendix H contains a description of the algorithm used to project new coal-to-gas plants and the pipeline quality gas produced.

2. Demand and Supply Representation

This chapter describes how supply and demand are represented within the NGTDM and the basic role that the Natural Gas Transmission and Distribution Module (NGTDM) fulfills in the NEMS. First, a general description of the NEMS is provided, along with an overview of the NGTDM. Second, the data passed to and from the NGTDM and other NEMS modules is described along with the methodology used within the NGTDM to transform the input values prior to their use in the model. The natural gas demand representation used in the module is described, followed by a section on the natural gas supply interface and representation, and concluding with a section on the representation of demand and supply in Alaska.

A Brief Overview of NEMS and the NGTDM

The NEMS represents all of the major fuel markets (crude oil and petroleum products, natural gas, coal, electricity, and imported energy) and iteratively solves for an annual supply/demand balance for each of the nine Census Divisions, accounting for the price responsiveness in both energy production and end-use demand, and for the interfuel substitution possibilities. NEMS solves for an equilibrium in each forecast year by iteratively operating a series of fuel supply and demand modules to compute the end-use prices and consumption of the fuels represented, effectively finding the intersection of the theoretical supply and demand curves reflected in these modules.[7] The end-use demand modules (for the residential, commercial, industrial, and transportation sectors) are detailed representations of the important factors driving energy consumption in each of these sectors. Using the delivered prices of each fuel, computed by the supply modules, the demand modules evaluate the consumption of each fuel, taking into consideration the interfuel substitution possibilities, the existing stock of fuel and fuel conversion burning equipment, and the level of economic activity. Conversely, the fuel conversion and supply modules determine the end-use prices needed in order to supply the amount of fuel demanded by the customers, as determined by the demand modules. Each supply module considers the factors relevant to that particular fuel, for example: the resource base for oil and gas, the transportation costs for coal, or the refinery configurations for petroleum products. Electric generators and refineries are both suppliers and consumers of energy.

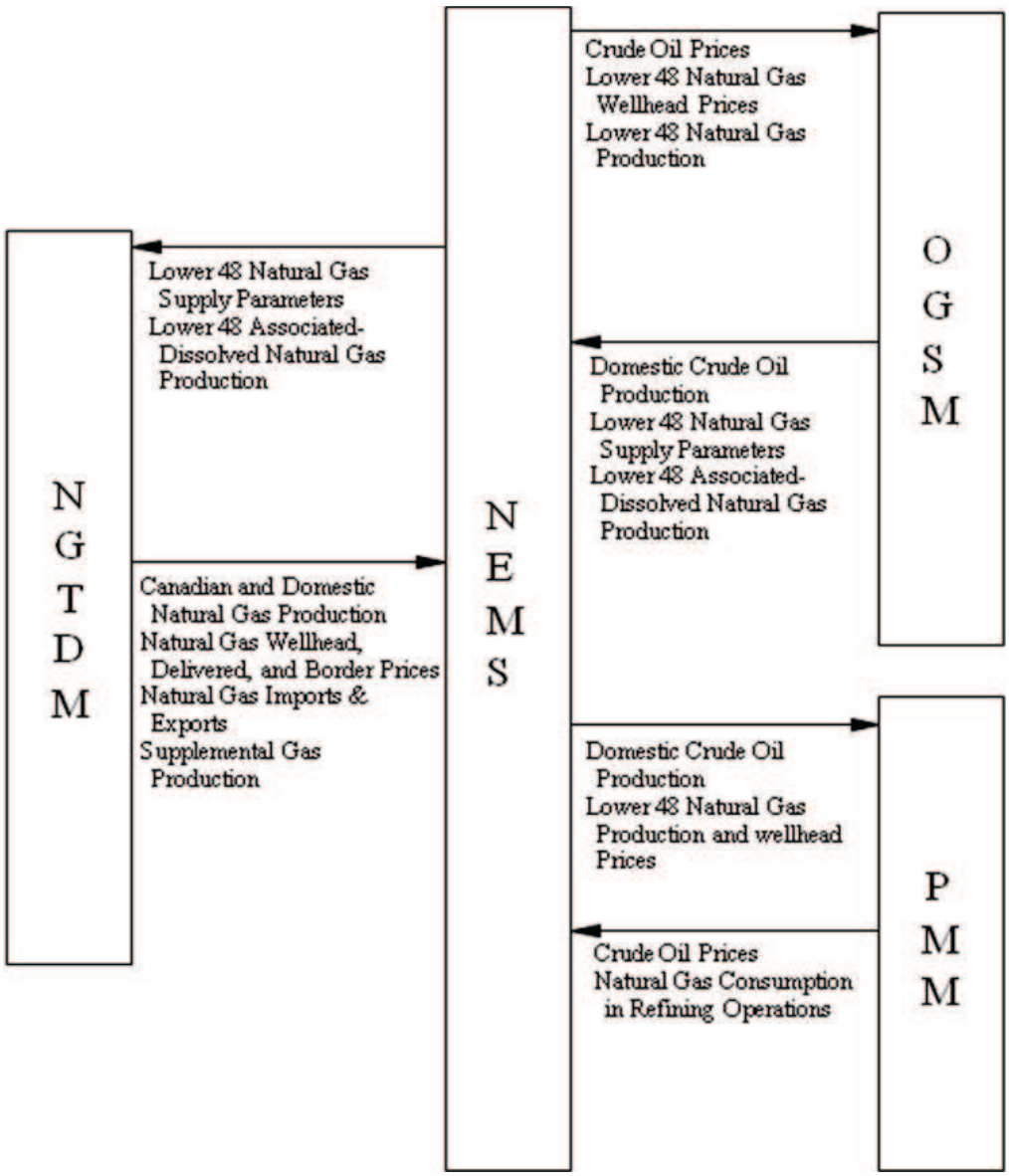
Within the NEMS system, the NGTDM provides the interface for natural gas between the Oil and Gas Supply Module (OGSM) and the demand modules in NEMS, including the Electricity Market Module (EMM). Since the other modules provide little, if any, information on markets outside of the United States, the NGTDM uses supply curves for liquefied natural gas (LNG) imports based on output results from EIA's separate International Natural Gas Model (INGM) and includes a simple representation of natural gas markets in Canada and Mexico in order to project LNG and pipeline import levels into the United States. The NGTDM estimates the price and flow of dry natural gas supplied internationally from the contiguous U.S. border[8] or

[7]A more detailed description of the NEMS system, including the convergence algorithm used, can be found in "Integrating Module of the National Energy Modeling System: Model Documentation 2010." DOE/EIA-M057(2010), May 2010 or "The National Energy Modeling System: An Overview 2009," DOE/EIA-0581(2009), October 2009.

[8]Natural gas exports are also accounted for within the model.

domestically from the wellhead (and indirectly from natural gas processing plants) to the domestic end-user. In so doing, the NGTDM models the markets for the transmission (pipeline companies) and distribution (local distribution companies) of natural gas in the contiguous United States.[9] The primary data flows between the NGTDM and the other oil and gas modules in NEMS, the Petroleum Market Module (PMM) and the OGSM are depicted in **Figure 2-1**.

Figure 2-1. Primary Data Flows between Oil and Gas Modules of NEMS



[9]Because of the distinct separation in the natural gas market between Alaska, Hawaii, and the contiguous United States, natural gas consumption in, and the associated supplies from, Alaska and Hawaii are modeled separately from the contiguous United States within the NGTDM.

In each NEMS iteration, the demand modules in NEMS provide the level of natural gas that would be consumed at the burner-tip in each region by the represented sector at the delivered price set by the NGTDM in the previous NEMS iteration. At the beginning of each forecast year during a model run, the OGSM provides an expected annual level of natural gas produced at the wellhead in each region represented, given the oil and gas wellhead prices from the previous forecast year. (Some supply sources (e.g., Canada) are modeled directly in the NGTDM.) The NGTDM uses this information to build "short-term" (annual or seasonal) supply and demand curves to approximate the supply or demand response to price. Given these short-term demand and supply curves, the NGTDM solves for the delivered, wellhead, and border prices that represent a natural gas market equilibrium, while accounting for the costs and market for transmission and distribution services (including its physical and regulatory constraints).[10] These solution prices, and associated production levels, are in turn passed to the OGSM and the demand modules, including the EMM, as primary input variables for the next NEMS iteration and/or forecast year. Most of the calculations within OGSM are performed only once each NEMS iteration, after the NEMS has converged to an equilibrium solution. Information from OGSM is passed as needed to the NGTDM to solve for the following forecast year.

The NGTDM is composed of three primary components or submodules: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS). The ITS is the central module of the NGTDM, since it is used to derive network flows and prices of natural gas in conjunction with a peak[11] and off-peak natural gas market equilibrium. Conceptually the ITS is a simplified representation of the natural gas transmission and distribution system, structured as a network composed of nodes and arcs. The other two primary components serve as satellite submodules to the ITS, providing parameters which define the tariffs to be charged along each of the interregional, intraregional, intrastate, and distribution segments. Data are also passed back to these satellite submodules from the ITS. Other parameters for defining the natural gas market (such as supply and demand curves) are derived based on information passed primarily from other NEMS modules. However in some cases, supply (e.g., synthetic gas production) and demand components (e.g., pipeline fuel) are modeled exclusively in the NGTDM.

The NGTDM is called once each NEMS iteration, but all submodules are not run for every call. The PTS is executed only once for each forecast year, on the first iteration for each year. The ITS and the DTS are executed once every NEMS iteration. The calling sequence of and the interaction among the NGTDM modules is as follows for each forecast year executed in NEMS:

First Iteration:

a. The PTS determines the revenue requirements associated with interregional / interstate pipeline company transportation and storage services, using a cost based approach, and uses this information and cost of expansion estimates as a basis in establishing fixed rates and volume dependent tariff curves (variable rates) for pipeline and storage usage.

[10]Parameters are provided by OGSM for the construction of supply curves for domestic non-associated natural gas production. The NGTDM establishes a supply curve for conventional Western Canada. The use of demand curves in the NGTDM is an option; the model can also respond to fixed consumption levels.

[11]The peak period covers the period from December through March; the off-peak period covers the remaining months.

b. The ITS establishes supply levels (e.g., for supplemental supplies) and supply curves for production and LNG imports based on information from other modules.

Each Iteration:

a. The DTS sets markups for intrastate transmission and for distribution services using econometric relationships based on historical data, largely driven by changes in consumption levels.
b. The ITS processes consumption levels from NEMS demand modules as required, (e.g., annual consumption levels are disaggregated into peak and off-peak levels) before determining a market equilibrium solution across the two-period NGTDM network.
c. The ITS employs an iterative process to determine a market equilibrium solution which balances the supply and demand for natural gas across a U.S./Canada network, thereby setting prices throughout the system and production and import levels. This operation is performed simultaneously for both the peak and off-peak periods.

Last Iteration:

a. In the process of establishing a network/market equilibrium, the ITS also determines the associated pipeline and storage capacity expansion requirements. These expansion levels are passed to the PTS and are used in the revenue requirements calculation for the next forecast year. One of the inputs to the NGTDM is "planned" pipeline and storage expansions. These are based on reported pending and commenced construction projects and analysts' judgment as to the likelihood of the project's completion. For the first two forecast years, the model does not allow builds beyond these planned expansion levels.
b. Other outputs from NGTDM are passed to report writing routines.

For the historical years (1990 through 2009), a modified version of the above process is followed to calibrate the model to history. Most, but not all, of the model components are known for the historical years. In a few cases, historical levels are available annually, but not for the peak and off-peak periods (e.g., the interstate flow of natural gas and regional wellhead prices). The primary unknowns are pipeline and storage tariffs and market hub prices. When prices are translated from the supply nodes, through the network to the end-user (or city gate) in the historical years, the resulting prices are compared against published values for city gate prices. These differentials (benchmark factors) are carried through and applied during the forecast years as a calibration mechanism. In the most recent historical year (2009) even fewer historical values are known; and the process is adjusted accordingly.

The primary outputs from the NGTDM, which are used as input in other NEMS modules, result from establishing a natural gas market equilibrium solution: delivered prices, wellhead and border crossing prices, non-associated natural gas production, and Canadian and LNG import levels. In addition, the NGTDM provides a forecast of lease and plant fuel consumption, pipeline fuel use, as well as pipeline and distributor tariffs, pipeline and storage capacity expansion, and interregional natural gas flows.

Natural Gas Demand Representation

Natural gas produced within the United States is consumed in lease and plant operations, delivered to consumers, exported internationally, or consumed as pipeline fuel. The consumption of gas as lease, plant, and pipeline fuel is determined within the NGTDM. Gas used in well, field, and lease operations and in natural gas processing plants is set equal to a historically observed percentage of dry gas production.[12] Pipeline fuel use depends on the amount of gas flowing through each region, as described in Chapter 4. The representation in the NGTDM of gas delivered to consumers is described below.

Classification of Natural Gas Consumers

Natural gas that is delivered to consumers is represented within the NEMS at the Census Division level and by five primary end-use sectors: residential, commercial, industrial, transportation, and electric generation.[13] These demands are further distinguished by customer class (core or non-core), reflecting the type of natural gas transmission and distribution service that is assumed to be predominately purchased. A "core" customer is expected to generally require guaranteed or firm service, particularly during peak days/periods during the year. A "non-core" customer is expected to require a lower quality of transmission services (non-firm service) and therefore, consume gas under a less certain and/or less continuous basis. While customers are distinguished by customer class for the purpose of assigning different delivered prices, the NGTDM does not explicitly distinguish firm versus non-firm transmission service. Currently in NEMS, all customers in the transportation, residential, and commercial sectors are classified as core.[14] Within the industrial sector the non-core segment includes the industrial boiler market and refineries; the core makes up the rest. The electric generating units defining each of the two customer classes modeled are as follows: (1) core − gas steam units or gas combined cycle units, (2) non-core − dual-fired turbine units, gas turbine units, or dual-fired steam plants (consuming both natural gas and residual fuel oil). [15]

For any given NEMS iteration and forecast year, the demand modules in NEMS determine the level of natural gas consumption for each region and customer class given the delivered price for the same region, class, and sector, as calculated by the NGTDM in the previous NEMS iteration. Within the NGTDM, each of these consumption levels (and its associated price) is used in

[12]The regional factors used in calculating lease and plant fuel consumption (PCTLP) are initially based on historical averages (1996 through 2009) and held constant throughout the forecast period. However, a model option allows for these factors to be scaled in the first one or two forecast years so that the resulting national lease and plant fuel consumption will match the annual published values presented in the latest available *Short-Term Energy Outlook* (STEO), DOE/EIA-0202), (Appendix E, STQLPIN). The adjustment attributable to benchmarking to STEO (if selected as an option) is phased out by the year STPHAS_YR (Appendix E). For *AEO2011* these factors were phased out by 2014. A similar adjustment is performed on the factors used in calculating pipeline fuel consumption using STEO values from STQGPTR (Appendix E).

[13]Natural gas burned in the transportation sector is defined as compressed natural gas or liquefied natural gas that is burned in natural gas vehicles; and the electric generation sector includes all electric power generators whose primary business is to sell electricity, or electricity and heat, to the public, including combined heat and power plants, small power producers, and exempt wholesale generators.

[14]The NEMS is structurally able to classify a segment of these sectors as non-core, but currently sets the non-core consumption at zero for the residential, commercial, and transportation sectors.

[15]Currently natural gas prices for the core and non-core segments of the electric generation sector are set to the same average value.

conjunction with an assumed price elasticity as a basis for building an annual demand curve. [The price elasticities are set to zero if fixed consumption levels are to be used.] These curves are used within the NGTDM to minimize the required number of NEMS iterations by approximating the demand response to a different price. In so doing, the price where the implied market equilibrium would be realized can be approximated. Each of these market equilibrium prices is passed to the appropriate demand module during the next NEMS iteration to determine the consumption level that the module would actually forecast at this price. Once the NEMS converges, the difference between the actual consumption, as determined by the NEMS demand modules, and the approximated consumption levels in the NGTDM are insignificant.

For all but the electric sector, the NGTDM disaggregates the annual Census division regional consumption levels into the regional and seasonal representation that the NGTDM requires. The regional representation for the electric generation sector differs from the other NEMS sectors as described below.

Regional/Seasonal Representations of Demand

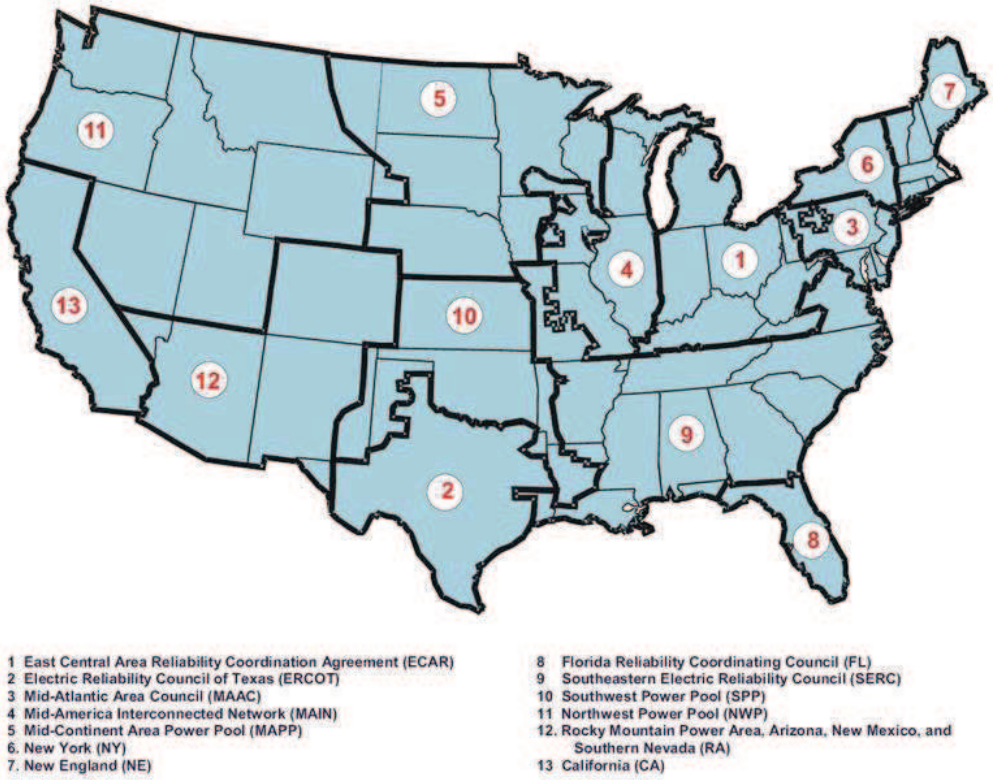
Natural gas consumption levels by all non-electric[16] sectors are provided by the NEMS demand modules for the nine Census divisions, the primary integrating regions represented in the NEMS. Alaska and Hawaii are included within the Pacific Census Division. The EMM represents the electricity generation process for 13 electricity supply regions, the nine North American Electric Reliability Council (NERC) Regions and four selected NERC Subregions (**Figure 2-2**). Within the EMM, the electric generators' consumption of natural gas is disaggregated into subregions that can be aggregated into Census Divisions or into the regions used in the NGTDM.

With the few following exceptions, the regional detail provided at a Census division level is adequate to build a simple network representative of the contiguous U.S. natural gas pipeline system. First, Alaska is not connected to the rest of the Nation by pipeline and is therefore treated separately from the contiguous Pacific Division in the NGTDM. Second, Florida receives its gas from a distinctly different route than the rest of the South Atlantic Division and is therefore isolated. A similar statement applies to Arizona and New Mexico relative to the Mountain Division. Finally, California is split off from the contiguous Pacific Division because of its relative size coupled with its unique energy related regulations. The resulting 12 primary regions represented in the NGTDM are referred to as the "NGTDM Regions" (as shown in **Figure 1-2**).

The regions represented in the EMM do not always align with State borders and generally do not share common borders with the Census divisions or NGTDM regions. Therefore, demand in the electric generation sector is represented in the NGTDM at a seventeen subregional (NGTDM/EMM) level which allows for a reasonable regional mapping between the EMM and the NGTDM regions (**Figure 2-3**). The seventeenth region is Alaska. Within the EMM, the disaggregation into subregions is based on the relative geographic location (and natural gas-fired generation capacity) of the current and proposed electricity generation plants within each region.

[16]The term "non-electric" sectors refer to sectors (other than commercial and industrial combined heat and power generators) that do not produce electricity using natural gas (i.e., the residential, commercial, industrial, and transportation demand sectors).

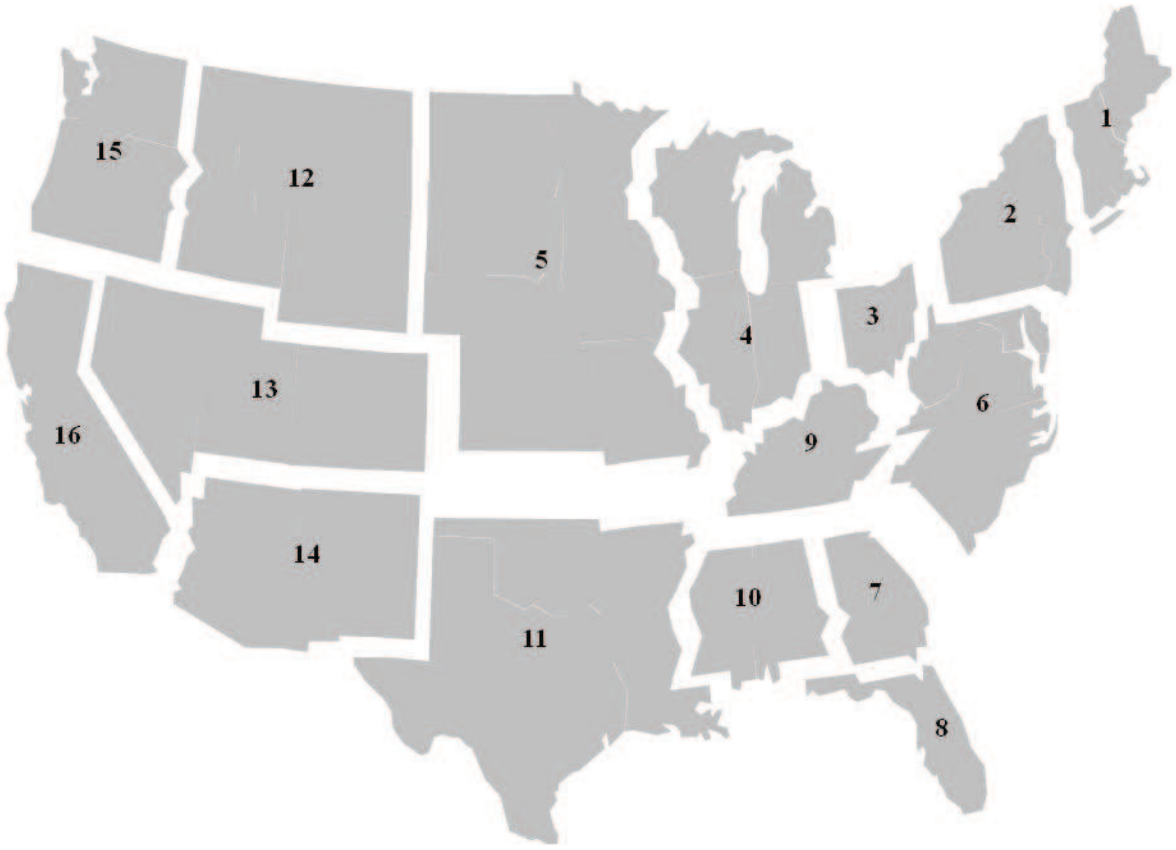
Figure 2-2. Electricity Market Module (EMM) Regions



Annual consumption levels for each of the non-electric sectors are disaggregated from the nine Census divisions to the two seasonal periods and the twelve NGTDM regions by applying average historical shares (2001 to 2009) that are held constant throughout the forecast (census − NG_CENSHR, seasons − PKSHR_DMD). For the Pacific Division, natural gas consumption estimates for Alaska are first subtracted to establish a consumption level for just the contiguous Pacific Division before the historical share is applied. The consumption of gas in Hawaii was considered to be negligible and is not handled separately. Within the NGTDM, a relatively simple series of equations (described later in the chapter) was included for approximating the consumption of natural gas by each non-electric sector in Alaska. These estimates, combined with the levels provided by the EMM for consumption by electric generators in Alaska, are used in the calculation of the production of natural gas in Alaska.

Unlike the non-electric sectors, the factors (core − PKSHR_UDMD_F, non-core − PKSHR_UDMD_I) for disaggregating the annual electric generator sector consumption levels (for each NGTDM/EMM region and customer type − core and non-core) into seasons are adjusted over the forecast period. Initially average historical shares (1994 to 2009, except New England − 1997 to 2009) are established as base level shares (core − BASN_PKSHR_UF,

Figure 2-3. NGTDM/EMM Regions



non-core − BASN_PKSHR_UI). The peak period shares are increased each year of the forecast by 0.5 percent (with a corresponding decrease in the off-peak shares) not to exceed 32 percent of the year.[17]

Natural Gas Demand Curves

While the primary analysis of energy demand takes place in the NEMS demand modules, the NGTDM itself directly incorporates price responsive demand curves to speed the overall convergence of NEMS and to improve the quality of the results obtained when the NGTDM is run as a stand-alone model. The NGTDM may also be executed to determine delivered prices for fixed consumption levels (represented by setting the price elasticity of demand in the demand curve equation to zero). The intent is to capture relatively minor movements in consumption levels from the provided base levels in response to price changes, not to accurately mimic the expected response of the NEMS demand modules. The form of the demand curves for the firm transmission service type for each non-electric sector and region is:

[17]The peak period covers 33 percent of the year.

$$NGDMD_CRVF_{s,r} = BASQTY_F_{s,r} * (PR / BASPR_F_{s,r})^{NONU_ELAS_F_s} \quad (1)$$

where,

$BASPR_F_{s,r}$ = delivered price to core sector s in NGTDM region r in the previous NEMS iteration (1987 dollars per Mcf)

$BASQTY_F_{s,r}$ = natural gas quantity which the NEMS demand modules indicate would be consumed at price BASPR_F by core sector s in NGTDM region r (Bcf)

$NONU_ELAS_F_s$ = short-term price elasticity of demand for core sector s (set to zero for *AEO2011* or to represent fixed consumption levels)

PR = delivered price at which demand is to be evaluated (1987 dollars per Mcf)

$NGDMD_CRVF_{s,r}$ = estimate of the natural gas which would be consumed by core sector s in region r at the price PR (Bcf)

s = core sector (1-residential, 2-commercial, 3-industrial, 4-transportation)

The form of the demand curve for the non-electric interruptible transmission service type is identical, with the following variables substituted: NGDMD_CRVI, BASPR_I, BASQTY_I, and NONU_ELAS_I (all set to zero for *AEO2011*). For the electric generation sector the form is identical as well, except there is no sector index and the regions represent the 16 NGTDM/EMM lower 48 regions, not the 12 NGTDM regions. The corresponding set of variables for the core and non-core electric generator demand curves are [NGUDMD_CRVF, BASUPR_F, BASUQTY_F, UTIL_ELAS_F] and [NGUDMD_CRVI, BASUPR_I, BASUQTY_I, UTIL_ELAS_I], respectively. For the *AEO2011* all of the electric generator demand curve elasticities were set to zero.

Domestic Natural Gas Supply Interface and Representation

The primary categories of natural gas supply represented in the NGTDM are non-associated and associated-dissolved gas from onshore and offshore U.S. regions; pipeline imports from Mexico; Eastern, Western (conventional and unconventional), and Arctic Canada production; LNG imports; natural gas production in Alaska (including that which is transported through Canada via pipeline[18]); synthetic natural gas produced from coal and from liquid hydrocarbons; and other supplemental supplies. Outside of Alaska (which is discussed in a later section) the only supply categories from this list that are allowed to vary within the NGTDM in response to a change in the current year's natural gas price are the non-associated gas from onshore and offshore U.S. regions, conventional gas from the Western Canada region, and LNG imports.[19]

[18] Several different options have been proposed for bringing stranded natural gas in Alaska to market (i.e., by pipeline, as LNG, and as liquids). Previously, the LNG option was deemed the least likely and is not considered in this version of the model, but will be reassessed in the future. The Petroleum Market Module forecasts the potential conversion of Alaska natural gas into liquids. The NGTDM allows for the building of a generic pipeline from Alaska into Alberta, although not at the same time as a MacKenzie Valley pipeline. The pipeline is assumed to have first access to the currently proved reserves in Alaska which are assumed to be producible at a relatively low cost given their association with oil production.

[19] Liquefied natural gas imports are set based on the price in the previous NEMS iteration and are effectively "fixed" when the NGTDM determines a natural gas market equilibrium solution; whereas the other two categories are determined as a part of the

The supply levels for the remaining categories are fixed at the beginning of each forecast year (i.e., before market clearing prices are determined), with the exception of associated-dissolved gas (determined in OGSM).[20] With the exception of LNG, the NGTDM applies average historical relationships to convert annual "fixed" supply levels to peak and off-peak values. These factors are held constant throughout the forecast period.

Within the OGSM, natural gas supply activities are modeled for 12 U.S. supply regions (6 onshore, 3 offshore, and 3 Alaskan geographic areas). The six onshore OGSM regions within the contiguous United States, shown in **Figure 2-4**, do not generally share common borders with the NGTDM regions. The NGTDM represents onshore supply for the 17 regions resulting from overlapping the OGSM and NGTDM regions (**Figure 2-5**). A separate component of the NGTDM models the foreign sources of gas that are transported via pipeline from Canada and Mexico. Seven Canadian and three Mexican border crossings demarcate the foreign pipeline interface in the NGTDM. Potential LNG imports are represented at each of the coastal NGTDM regions; however, import volumes will only be projected based on where existing or exogenously set additional regasification capacity exists (e.g., if a facility is under construction or deemed highly likely to be constructed).[21]

"Variable" Dry Natural Gas Production Supply Curve

The two "variable" (or price responsive) natural gas supply categories represented in the model are domestic non-associated production and total production from the Western Canadian Sedimentary Basin (WCSB). Non-associated natural gas is largely defined as gas that is produced from gas wells, and is assumed to vary in response to a change in the natural gas price. Associated-dissolved gas is defined as gas that is produced from oil wells and can be classified as a byproduct in the oil production process. Each domestic supply curve is defined through its associated parameters as being net of lease and plant fuel consumption (i.e., the amount of dry gas available for market after any necessary processing and before being transported via pipeline). For both of these categories, the supply curve represents annual production levels. The methodology for translating this annual form into a seasonal representation is presented in Chapter 4.

The supply curve for regional non-associated lower 48 natural gas production and for WCSB production is built from a price/quantity (P/Q) pair, where quantity is the "expected" production (XQBASE) or the base production level as defined by the product of reserves times the "expected" production-to-reserves ratio (as set in the OGSM) and price is the projected wellhead price (XPBASE, presented below) for the expected production. The basic assumption behind the curve is that the realized market price will increase from the base price if the current year's production levels exceed the expected production; and the opposite will occur if current production is less In addition, it is assumed that the relative price response will likely be greater for a marginal increase in production above the expected production, compared to below. To

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market equilibrium process in the NGTDM.

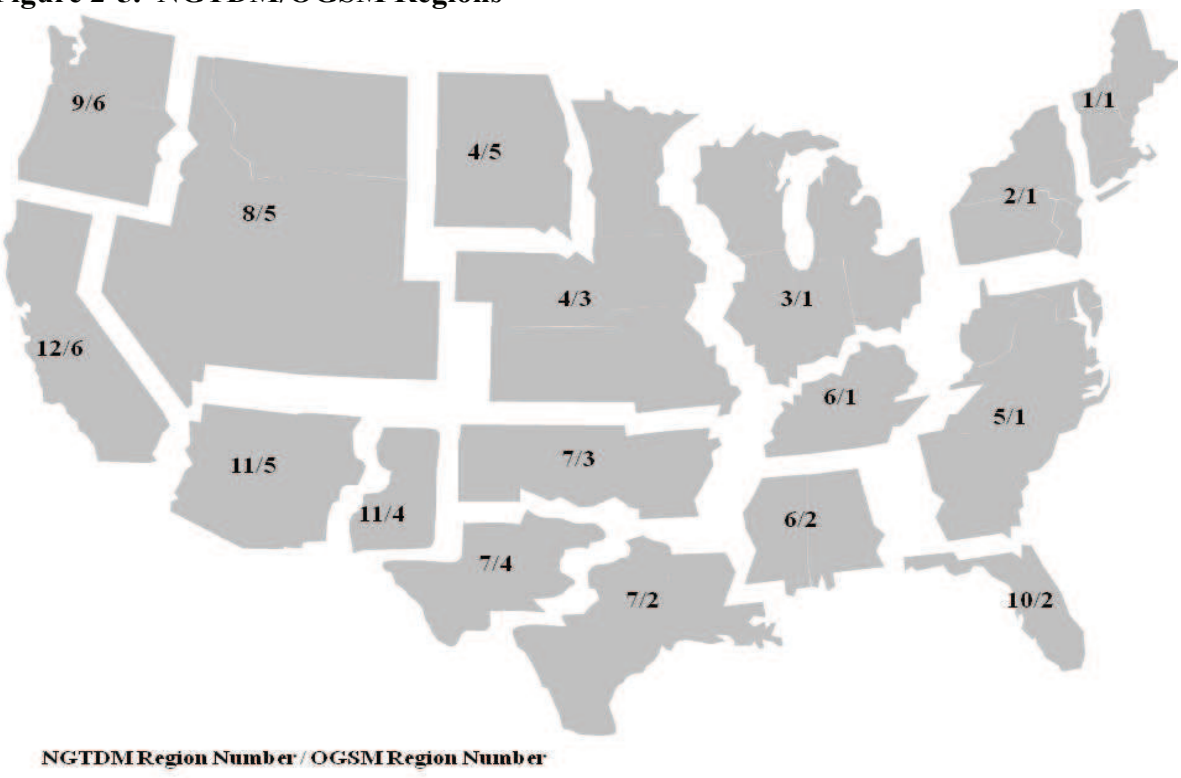
[20]For programming convenience natural gas produced with oil shales (OGSHALENG) is also added to this category.

[21]Structurally an LNG regasification terminal in the Bahamas would be represented as entering into Florida and be reported as pipeline imports, although modeled as LNG imports. No regasification terminals are considered for Alaska or Hawaii.

Figure 2-4. Oil and Gas Supply Module (OGSM) Regions



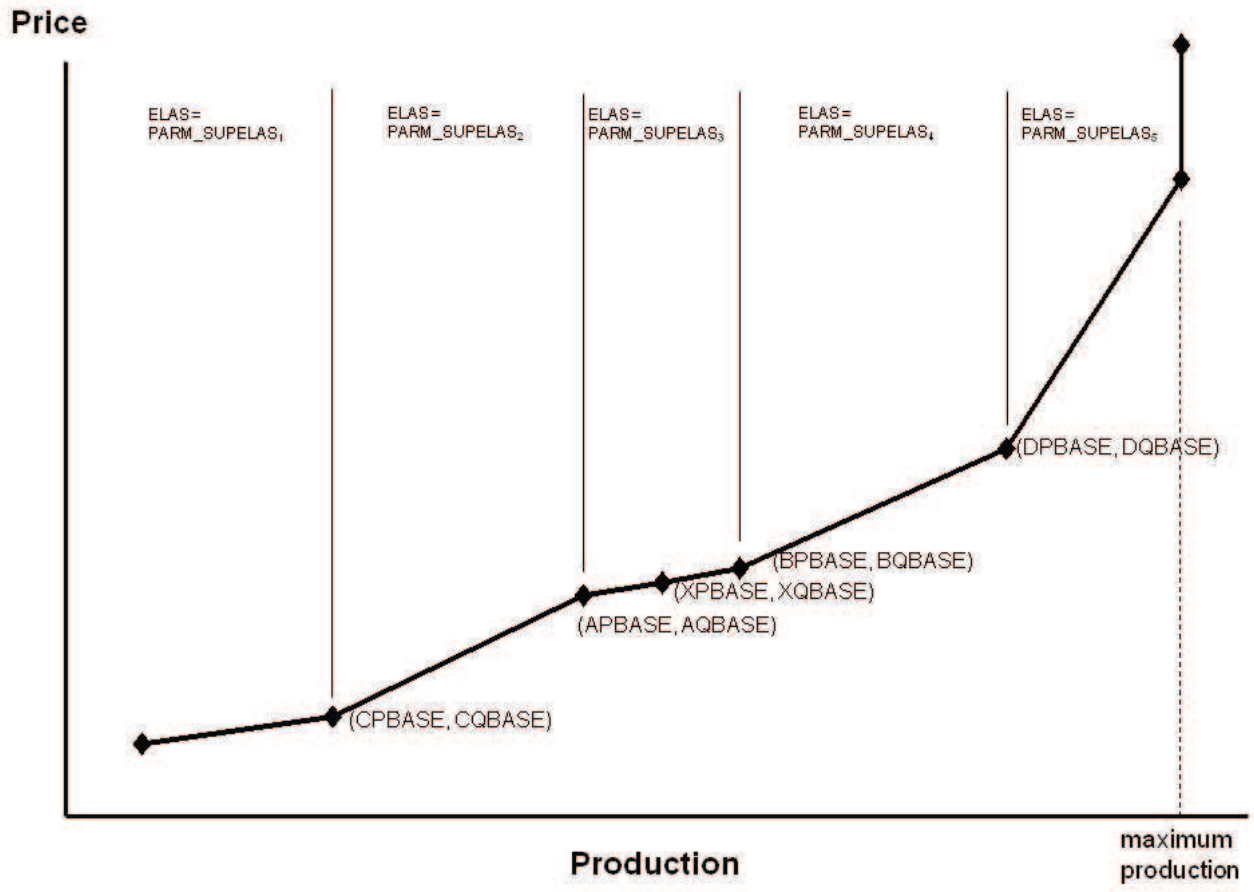
Figure 2-5. NGTDM/OGSM Regions



represent these assumptions, five segments of the curve are defined from the base point. The middle segment is centered around the base point, extends plus or minus a percent (PARM_SUPCRV3, Appendix E) from the base quantity, and if activated, is generally set nearly horizontal (i.e., there is little price response to a quantity change). The next two segments, on either side of the middle, extend more vertically (with a positive slope), and reach plus or minus a percent (PARM_SUPCRV5, Appendix E) beyond the end of the middle segment. The remaining two segments extend the curve above and below even further for the case with relatively large annual production changes, and can be assigned the same or different slopes from their adjacent segments. The slope of the upper segment(s) is generally set greater than or equal to that of the lower segment(s). An illustrative presentation of the supply curve is provided in **Figure 2-6**. The general structure for all five segments of the supply curve, in terms of defining price (NGSUP_PR) as a function of the quantity or production level (QVAR), is:

$$NGSUP_PR = PBASE * (((\frac{1}{ELAS}) * (\frac{QVAR - QBASE}{QBASE})) + 1) \quad (2)$$

Figure 2-6. Generic Supply Curve



A more familiar form of this equation is the definition of elasticity (ξ) as: $\xi = (\Delta Q/Q_o) / (\Delta P/P_o)$, where Δ symbolizes "the change in" and Q_o and P_o represent a base level price/quantity pair.

Each of the five segments is assigned different values for the variables ELAS, PBASE, and QBASE:

Lowest segment:

$$PBASE = CPBASE = APBASE * (1 - (PARM_SUPCRV5/PARM_SUPELAS2)) \quad (3)$$

$$QBASE = CQBASE = AQBASE * (1 - PARM_SUPCRV5) \quad (4)$$

$$ELAS = PARM_SUPELAS1 = 0.40 \quad (5)$$

Lower segment:

$$PBASE = APBASE = XPBASE * (1 - (PARM_SUPCRV3/PARM_SUPELAS3)) \quad (6)$$

$$QBASE = AQBASE = XQBASE * (1 - PARM_SUPCRV3) \quad (7)$$

$$ELAS = PARM_SUPELAS2 = 0.35 \quad (8)$$

Middle segment:
(in historical years)

$$PBASE = XPBASE = historical\ wellhead\ price \quad (9)$$

$$QBASE = XQBASE = QSUP_s/(1 - PERCNT_n) \quad (10)$$

(in forecast years)

$$PBASE = XPBASE = ZWPRLAG_s \quad (11)$$

$$QBASE = XQBASE = ZOGRESNG_s * ZOGPRRNG_s \quad (12)$$

$$ELAS = PARM_SUPELAS3 = 1.00 \quad (13)$$

Upper segment:

$$PBASE = BPBASE = XPBASE * (1 + (PARM_SUPCRV3/PARM_SUPELAS3)) \quad (14)$$

$$QBASE = BQBASE = XQBASE * (1 + PARM_SUPCRV3) \quad (15)$$

$$ELAS = PARM_SUPELAS4 = 0.25 \quad (16)$$

Uppermost segment:

$$PBASE = DPBASE = BPBASE * (1 + (PARM_SUPCRV5/PARM_SUPELAS4)) \quad (17)$$

$$QBASE = DQBASE = BQBASE * (1 + PARM_SUPCRV5) \quad (18)$$

$$ELAS = PARM_SUPELAS5 = 0.20 \quad (19)$$

where,

NGSUP_PR = Wellhead price (1987$/Mcf)
QVAR = Production, including lease & plant (Bcf)
XPBASE = Base wellhead price on the supply curve (1987$/Mcf)
XQBASE = Base wellhead production on the supply curve (Bcf)
PBASE = Base wellhead price on a supply curve segment (1987$/Mcf)
QBASE = Base wellhead production on a supply curve segment (Bcf)
AQBASE, BQBASE, CQBASE, DQBASE = Production levels defining the supply curve in Figure 2-6 (Bcf)
APBASE, BPBASE, CPBASE, DPBASE = Price levels defining the supply curve in Figure 2-6 (Bcf)
ELAS = Elasticity (percent change in quantity over percent change in price) (analyst judgment)
PARM_SUPCRV3 = (defined in preceding paragraph)
PARM_SUPCRV5 = (defined in preceding paragraph)
PARM_SUPELAS# = Elasticity (percentage change in quantity over percentage change in price) on different segments (#) of supply curve
$ZWPRLAG_s$ = Lagged (last year's) wellhead price for supply source s (1987/Mcf)
$ZOGRESNG_s$ = Natural gas proved reserves for supply source s at the beginning of the year (Bcf)
$ZOGPRRNG_s$ = Natural gas production to reserves ratio for supply sources (fraction)
$PERCNT_n$ = Percent lease and plant
s = supply source
n = region/node
t = year

The parameters above will be set depending on the location of QVAR relative to the base quantity (XQBASE) (i.e., on which segment of the curve that QVAR falls). In the above equation, the QVAR variable includes lease and plant fuel consumption. Since the ITM domestic production quantity (VALUE) represents supply levels net of lease and plant, this value must be adjusted once it is sent to the supply curve function, and before it can be evaluated, to generate a corresponding supply price. The adjustment equation is:

$$QVAR = (VALUE - FIXSUP) / (1.0 - PERCNT_n)$$

[where, $FIXSUP = ZOGCCAPPRD_s * (1.0 - PERCNT_n)$]

where,

QVAR = Production, including lease and plant consumption
VALUE = Production, net of lease and plant consumption

$PERCNT_n$ = Percent lease and plant consumption in region/node n (set to PCTLP, set to zero for Canada)
$ZOGCCAPPRD_s$ = Coalbed gas production related to the Climate Change Action Plan (from OGSM)[22]
FIXSUP = ZOGCCAPPRD net of lease and plant consumption
s = NGTDM/OGSM supply region
n = region/node

Associated-Dissolved Natural Gas Production

Associated-dissolved natural gas refers to the natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved). The production of associated-dissolved natural gas is tied directly with the production (and price) of crude oil. The OGSM projects the level of associated-dissolved natural gas production and the results are passed to the NGTDM for each iteration and forecast year of the NEMS. Within the NGTDM, associated-dissolved natural gas production is considered "fixed" for a given forecast year and is split into peak and off-peak values based on average (1994-2009) historical shares of total (including non-associated) peak production in the year (PKSHR_PROD).

Supplemental Gas Sources

Existing sources for synthetically produced pipeline-quality, natural gas and other supplemental supplies are assumed to continue to produce at historical levels. While the NGTDM has an algorithm (see Appendix H) to project potential new coal-to-gas plants and their gas production, the annual production of synthetic natural gas from coal at the existing plant is exogenously specified (Appendix E, SNGCOAL), independent of the price of natural gas in the current forecast year. The *AEO2011* forecast assumes that the sole existing plant (the Great Plains Coal Gasification Plant in North Dakota) will continue to operate at recent historical levels indefinitely. Regional forecast values for other supplemental supplies (SNGOTH) are set at historical averages (2003 to 2008) and held constant over the forecast period. Synthetic natural gas is no longer produced from liquid hydrocarbons in the continental United States; although small amounts were produced in Illinois in some historical years. This production level (SNGLIQ) is set to zero for the forecast. The small amount produced in Hawaii is accounted for in the output reports (set to the historical average from 1997 to 2008). If the option is set for the first two forecast years of the model to be calibrated to the *Short Term Energy Outlook (STEO)* forecast, then these three categories of supplemental gas are similarly scaled so that their sum will equal the national annual forecast for total supplemental supplies published in the *STEO* (Appendix E, STOGPRSUP). To guarantee a smooth transition, the scaling factor in the last STEO year can be progressively phased out over the first STPHAS_YR (Appendix E) forecast years of the NGTDM. Regional peak and off-peak supply levels for the three supplemental gas supplies are generated by applying the same average (1990-2009) historical share (PKSHR_SUPLM) of national supplemental supplies in the peak period.

[22]This special production category is not included in the reserves and production-to-reserve ratios calculated in the OGSM, so it was necessary to account for it separately when relevant. It is no longer relevant and is set to zero.

Natural Gas Imports and Exports Interface and Representation

The NGTDM sets the parameters for projecting gas imported through LNG facilities, the parameters and forecast values associated with the Canada gas market, and the projected values for imports from and exports to Mexico.

Canada

A node for east and west Canada is included in the NGTDM equilibration network, as well as seven border crossings. The model includes a representation/accounting of the U.S. border crossing pipeline capacity, east and west seasonal storage transfers, east and west consumption, east and west LNG imports (described in a later section), eastern production, conventional/tight sands production in the west, and coalbed/shale production. The ultimate determination of the import volumes into the United States occurs in the equilibration process of the NGTDM.

Base level consumption of natural gas in Eastern and Western Canada (Appendix E, CN_DMD), including gas used in lease, plant, and pipeline operations, is set exogenously,[23] and ultimately split into seasonal periods using PKSHR_CDMD (Appendix E). The projected level of oil produced from oil sands is also set exogenously to the NGTDM (based on the same source) and varies depending on the world oil price case. Starting in a recent historical year (Appendix E, YDCL_GASREQ), the natural gas required to support the oil sands production is set at an assumed ratio (Appendix E, INIT_GASREQ) of the oil sands production. Over the projection period this ratio is assumed to decline with technological improvements and as other fuel options become viable. The applied ratio in year t is set by multiplying the initially assumed rate by $(t\text{-}YDCL_GASREQ+1)^{DECL_GASREQ}$, where DECL_GASREQ is assumed based on anecdotal information (Appendix E). The oil sands related gas consumption under reference case world oil prices is subtracted from the base level total consumption and the remaining volumes are adjusted slightly based on differences in the world oil price in the model run versus the world oil price used in setting the base level consumption, using an assumed elasticity (Appendix E, CONNOL_ELAS). Finally, total consumption is set to this adjusted value plus the calculated gas consumed for oil sands production under the world oil price case selected. Oil sands production is assumed to just occur in Western Canada.

Currently, the NGTDM exogenously sets a forecast of the physical capacity of natural gas pipelines crossing at seven border points from Canada into the United States (excluding any expansion related to the building of an Alaska pipeline). This option can also be used within the model, if border crossing capacity is set endogenously, to establish a minimum pipeline build level (Appendix E, ACTPCAP and PLANPCAP). The model allows for an endogenous setting of annual Canadian pipeline expansion at each Canada/U.S. border crossing point based on the annual growth rate of consumption in the U.S. market it predominately serves. The resulting physical capacity limit is then multiplied by a set of exogenously specified maximum utilization rates for each seasonal period to establish maximum effective capacity limits for these pipelines (Appendix E, PKUTZ and OPUTZ). “Effective capacity” is defined as the maximum seasonal,

[23] se values were based on projections taken from the *International Energy Outlook 2010*.

physically sustainable, capacity of a pipeline times the assumed maximum utilization rate. It should be noted that some of the natural gas on these lines passes through the United States only temporarily before reentering Canada, and therefore is not classified as imports.[24] If a decision is made to construct a pipeline from Alaska (or the MacKenzie Delta) to Alberta, the import pipeline capacity added from the time the decision is made until the pipeline is in service is tracked. This amount is subtracted from the size of the pipeline to Alberta to arrive at an approximation for the amount of additional import capacity that will be needed to bring the Alaska or MacKenzie[25] gas to the United States. This total volume is apportioned to the pipeline capacity at the western import border crossings according to their relative size at the time.

Conventional Western Canada

The vast majority of natural gas produced in Canada currently is from the WCSB. Therefore, a different approach was used in modeling supplies from this region. The model consists of a series of estimated and reserves accounting equations for forecasting conventional (including from tight formations)[26] wells drilled, reserves added, reserve levels, and expected production-to-reserve ratios in the WCSB. Drilling activity, measured as the number of successful natural gas wells drilled, is estimated directly as a function of various market drivers rather than as a function of expected profitability. No distinction is made between wells for exploration and development. Next, an econometrically specified finding rate is applied to the successful wells to determine reserve additions; a reserves accounting procedure yields reserve estimates (beginning of year reserves). Finally an estimated extraction rate determines production potential [production-to-reserves ratio (PRR)].

Wells Determination

The total number of successful conventional natural gas wells drilled in Western Canada each year is forecasted econometrically as a function of the Canadian natural gas wellhead price, remaining undiscovered resources, last year's production-to-reserve ratio, and a proxy term for the drilling cost per well, as follows:

$$\begin{aligned} SUCWELL_t = \exp(-1.85639) * CN_PRC00_t^{1.09939} * URRCAN_t^{1.57373} \\ * CST_PRXYLAG^{-0.86063} * \exp(\, 33.6237 * CURPRRCAN_{t-1}\,) \end{aligned} \quad (20)$$

where,

[24]A significant amount of natural gas flows into Minnesota from Canada on an annual basis only to be routed back to Canada through Michigan. The levels of gas in this category are specified exogenously (Appendix E, FLOW_THRU_IN) and split into peak and off-peak levels based on average (1990-2009 historically based shares for general Canadian imports (PKSHR_ICAN).

[25]All of the gas from the MacKenzie Delta is not necessarily targeted for the U.S. market directly. Although it is anticipated that the additional supply in the Canadian system will reduce prices and increase the demand for Canadian gas in the United States. The methodology for representing natural gas production in the MacKenzie Delta and the associated pipeline is described in the section titled "Alaskan Natural Gas Routine."

[26]Since current data tend to combine statistics for drilling and production from conventional sources and that from tight gas formations, the model does not distinguish the two at present. The conventional resource estimate was increased by 1.5 percent per year as a rough estimate of the future contribution from resource appreciation and from tight formations until more reliable estimates can be generated. For the rest of the discussion on Canada, the use of the term "conventional" should be assumed to include gas from tight formations.

$SUCWELL_t$ = total conventional successful gas wells completed in Western Canada in year t

CN_PRC00_t = average Western Canada wellhead price per Mcf of natural gas in 2000 US dollars in year t

$URRCAN_t$ = remaining conventional undiscovered recoverable gas resources in the beginning of year t in Western Canada in (Bcf), specified below

CST_PRXYLAG = proxy term to reflect the change in drilling costs per well, projected into the future based on projections for the average lower 48 drilling costs the previous forecast year

CURPRRCAN = expected production-to-reserve ratio from the previous forecast year, specified below

Parameter values and details about the estimation of this equation can be found in Table F11 of Appendix F. The number of wells is restricted to increase by no more than 30 percent annually.

Reserve Additions

The reserve additions algorithm calculates units of gas added to Western Canadian Sedimentary Basin proved reserves. The methodology for conversion of gas resources into proved reserves is a critically important aspect of supply modeling. The actual process through which gas becomes proved reserves is a highly complex one. This section presents a methodology that is representative of the major phases that occur; although, by necessity, it is a simplification from a highly complex reality.

Gas reserve additions are calculated using a finding rate equation. Typical finding rate equations relate reserves added to 1) wells or feet drilled in such a way that reserve additions per well decline as more wells are drilled, and/or 2) remaining resources in such a way that reserve additions per well decline as remaining resources deplete. The reason for this is, all else being equal, the larger prospects typically are drilled first. Consequently, the finding rate can be expected to decline as a region matures, although the rate of decline and the functional forms are a subject of considerable debate. In previous versions of the model the finding rate (reserves added per well) was assumption based, while the current version is econometrically estimated using the following:

$$FRCAN_t = \exp\{(1-0.428588)*-25.3204\} * URRCAN_t^{2.13897} * FRLAG^{0.428588} * URRCAN_{t-1}^{--0.428588*2.13897}] \quad (21)$$

where,

$FRCAN_t$ = finding rate in year t (Bcf per well)

FRLAG = finding rate in year t-1 (Bcf per well)

$URRCAN_t$ = remaining conventional gas recoverable resources in year t in Western Canada in (Bcf)

Parameter values and details about the estimation of this equation can be found in Table F12 of Appendix F. Remaining conventional plus tight gas recoverable resources are initialized in 2004 and set each year thereafter as follows:

$$URRCAN_t = RESBASE * (1 + RESTECH)^T - CUMRCAN \quad (22)$$

where,

RESBASE = initial recoverable resources in 2004 (set at 92,800 Bcf) [27]
RESTECH = assumed rate of increase, primarily due to the contribution from tight gas formations, but also attributable to technological improvement (1.5 percent or 0.015)
$CUMRCAN_t$ = cumulative reserves added since initial year of 2004 in Bcf
T = the forecast year (t) minus the base year of 2004.

Total reserve additions in period t are given by:

$$RESADCAN_t = FRCAN_t * SUCWELL_t \quad (23)$$

where,

$RESADCAN_t$ = reserve additions in year t, in BCF
$FRCAN_{t-1}$ = finding rate in the previous year, in BCF per well
$SUCWELL_t$ = successful gas wells drilled in year t

Total end-of-year proved reserves for each period equal proved reserves from the previous period plus new reserve additions less production.

$$RESBOYCAN_{t+1} = CURRESCAN_t + RESADCAN_t - OGPRDCAN_t \quad (24)$$

where,

$RESBOYCAN_{t+1}$ = beginning of year reserves for year t+1, in BCF
$CURRESCAN_t$ = beginning of year reserves for t, in BCF
$RESADCAN_t$ = reserve additions in year t, in BCF
$OGPRDCAN_t$ = production in year t, in BCF
t = forecast year

When rapid and slow technological progress cases are run, the forecasted values for the number of successful wells and for the expected production-to-reserve ratio for new wells are adjusted accordingly.

Gas Production

Production is commonly modeled using a production-to-reserves ratio. A major advantage to this approach is its transparency. Additionally, the performance of this function in the aggregate is

[27]Source: National Energy Board, "Canada's Conventional Natural Gas Resources: A Status Report," Table 1.1A, April 2004.

consistent with its application on the micro level. The production-to-reserves ratio, as the relative measure of reserves drawdown, represents the rate of extraction, given any stock of reserves.

Conventional gas production in the WCSB in year t is determined in the NGTDM through a market equilibrium mechanism using a supply curve based on an expected production level provided by the OGSM. The realized extraction is likely to be different. The expected or normal operating level of production is set as the product of the beginning-of-year reserves (RESBOYCAN) and an expected extraction rate under normal operating conditions. This expected production-to-reserve ratio is estimated as follows:

$$PRRATCAN_t = \frac{e^{-72.1364+0.117911*\ln SUCWELL_t+0.041469*\ln FRCAN_t+0.03437*RLYR}}{1+e^{-72.1364+0.117911*\ln SUCWELL_t+0.041469*\ln FRCAN_t+0.03437*RLYR}} * \left(\frac{PRRATCAN_{t-1}}{1-PRRATCAN_{t-1}}\right)^{0.916835} * e^{-0.916835*(-72.1364+0.117911*\ln SUCWELL_{t-1}+0.041469*\ln FRCAN_{t-1}+0.03437*(RLYR-1))} \quad (25)$$

where,

$PRRATCAN_t$ = expected production-to-reserve natural gas ratio in Western Canada for conventional and tight gas
$FRCAN_t$ = finding rate in year t, in BCF per well
$SUCWELL_t$ = successful gas wells drilled in year t
RLYR = calendar year

Parameter values and details about the estimation of this equation can be found in Table F13 of Appendix F. The resulting production-to-reserve ratio is limited, so as not to increase or decrease more than 5 percent from one year to the next and to stay within the range of 0.7 to 0.12.

The potential or expected production level is used within the NGTDM to build a supply curve for conventional and tight natural gas production in Western Canada. The form of this supply curve is effectively the same as the one used to represent non-associated natural gas production in lower 48 regions. This curve is described later in this chapter, with the exceptions related to Canada noted. A primary difference is that the supply curve for the lower 48 States represents non-associated natural gas production net of lease and plant fuel consumption; whereas the Western Canada supply curve represents total conventional and tight natural gas production inclusive of lease and plant fuel consumption.

Canada Shale and Coalbed

Natural gas produced from other unconventional sources (coal beds and shale) in Western Canada (PRD2) is based on an assumed production profile, with the area under the curve equal to the assumed ultimate recovery (CUR_ULTRES). The production level is initially specified in terms of the forecast year and is set using one functional form before reaching its peak production level and a second functional form after reaching its peak production level. Before reaching peak production, the production levels are assumed to follow a quadratic form, where the level of production is zero in the first year (LSTYR0) and reaches its peak level (PKPRD) in

the peak year (PKIYR). The area under the assumed production function equals the assumed technically recoverable resource level (CUR_ULTRES) times the assumed percentage (PERRES) produced before hitting the peak level. After peak production the production path is assumed to decline linearly to the last year (LSTYR) when production is again zero. The two curves meet in the peak year (PKIYR) when both have a value equal to the peak production level (PKPRD). The actual production volumes are adjusted to reflect assumed technological improvement and by a factor that depends on the difference between an assumed price trajectory and the actual price projected in the model. The specifics follow:

Before Peak Production

Assumptions:

production function

$$PRD2 = PARMA*(PRDIYR - PKIYR)^2 + PARMB \quad (26)$$

area under the production function

$$CUR_ULTRES * PERRES$$

$$\int_{LSTYR0}^{PKIYR} [PARMA * (PRDIYR - PKIYR)^2 + PARMB]\, dPRDIYR \quad (27)$$

production in year LSTYR0:

$$0 = PARMA*(LSTYR0 - PKIYR)^2 + PARMB \quad (28)$$

production in peak year when PRDIYR = PKIYR

$$PKPRD = PARMA*(PKIYR - PKIYR)^2 + PARMB = PARMB \quad (29)$$

Derived from above:

$$PARMA = \frac{-3}{2} * \frac{CUR_ULTRES * PERRES}{(PKIYR - LSTYRO)^3} \quad (30)$$

$$PARMB = -PARMA*(LSTYRO - PKIYR)^2 \quad (31)$$

After Peak Production

Assumptions:

production function

$$PRD2 = (PARMC*PRDIYR) + PARMD \quad (32)$$

area under the production function

$$CUR_ULTRES*(1 - PERRES) = \int_{PKIYR}^{LSTYR} [(PARMC* PRDIYR) + PARMD]\, dPRDIYR \quad (33)$$

production in peak year when PRDIYR = PKIYR

$$PKPRD = PARMB = (PARMC * PKIYR) + PARMD \quad (34)$$

production in last year LSTYR

$$0 = (PARMC * LSTYR) + PARMD \quad (35)$$

Derived from above:

$$PARMC = \frac{-PARMB^2}{2*CUR_ULTRES*(1-PERRES)} \quad (36)$$

$$LSTYR = \frac{2*CUR_ULTRES*(1-PERRES)}{PARMB} + PKIYR \quad (37)$$

$$PARMD = -PARMC*LSTYR \quad (38)$$

given,

$$CUR_ULTRES = ULTRES*(1+RESTECH)^{(MODYR-RESBASE)}*(1+RESADJ) \quad (39)$$

and,

PRD2	=	Unadjusted Canada unconventional gas production (Bcf)
PKPRD	=	Peak production level in year PKIYR
CUR_ULTRES	=	Estimate of ultimate recovery of natural gas from unconventional Canada sources in the current forecast year (Bcf)
ULTRES	=	Estimate of ultimate recovery of natural gas from unconventional Canada sources in the year RESBASE (8,000 Bcf for coalbed in 2008 and 153,000 Bcf for shale in 2011, based on assumed resource levels used in EIA's International Natural Gas Model for the *International Energy Outlook 2010*.
RESBASE	=	Year associated with CUR_ULTRES
RESTECH	=	Technology factor to increase resource estimate over time (1.0)
MODYR	=	Current forecast year
RESADJ	=	Scenario specific resource adjustment factor (default value of 0.0)
PERRES	=	Percent of ultimate resource produced before the peak year of production (0.50, fraction)
PKIYR	=	Assumed peak year of production (2045)
LSTYR0	=	Last year of zero production (2004)
PRDIYR	=	Implied year of production along cumulative production path after price adjustment

The actual production is set by taking the unadjusted unconventional gas production (PRD2) and multiplying it by a price adjustment factor, as well as a technology factor. The price adjustment factor (PRCADJ) is based on the degree to which the actual price in the previous forecast year compares against a prespecified expected price path (exprc), represented by the functional form: exprc = (2.0 + [0.08*(MODYR-2008)]. The price adjustment factor is set to the price in the previous forecast year divided by the expected price, all raised to the 0.1 power. Technology is

assumed to progressively increase production by 1 percent per year (TECHGRW) more than it would have been otherwise (e.g., in the fifth forecast year production is increased by 5 percent above what it would have been otherwise). [28] Once the production is established for a given forecast year, the value of PRDIYR is adjusted to reflect the actual production in the previous year and incremented by 1 for the next forecast year.

The remaining forecast elements used in representing the Canada gas market are set exogenously in the NGTDM. When required, such annual forecasts are split into peak and off-peak values using historically based or assumed peak shares that are held constant throughout the forecast. For example, the level of natural gas exports (Appendix E, CANEXP) are currently set exogenously to NEMS, are distinguished by seven Canada/U.S. border crossings, and are split between peak and off-peak periods by applying average (1992 to 2009, Appendix E, PKSHR_ECAN) historical shares to the assumed annual levels. While most Canadian import levels into the U.S. are set endogenously, the flow from Eastern Canada into the East North Central region is secondary to the flow going in the opposite direction and is therefore set exogenously (Appendix E, Q23TO3). "Fixed" supply values for the entire Eastern Canada region are set exogenously (Appendix E, CN_FIXSUP)[29] and split into peak and off-peak periods using PKSHR_PROD (Appendix E).

Mexico

The Mexico model is largely based on exogenously specified assumptions about consumption and production growth rates and LNG import levels. For the most part, natural gas imports from Mexico are set exogenously for each of the three border crossing points with the United States, with the exception of any gas that is imported into Baja, Mexico, in liquid form only to be exported to the United States. Exports to Mexico from the United States are established before the NGTDM equilibrates and represents the required level to balance the assumed consumption in (and exports from) Mexico against domestic production and LNG imports. The supply levels are also largely assumption based, but are set to vary to a degree with changes in the expected wellhead price in the United States. Peak and off-peak values for imports from and exports to Mexico are based on average historical shares (1994 or 1991 to 2009, PKSHR_IMEX and PKSHR_EMEX, respectively).

Mexican gas trade is a complex issue, as a range of non-economic factors will influence, if not determine, future flows of gas between the United States and Mexico. Uncertainty surrounding Mexican/U.S. trade is great enough that not only is the magnitude of flow for any future year in doubt, but also the direction of net flows. Despite the uncertainty and the significant influence of non-economic factors that influence Mexican gas trade with the United States, a methodology to anticipate the path of future Mexican imports from, and exports to, the United States has been incorporated into the NGTDM. This outlook is generated using assumptions regarding regional supply from indigenous production and/or liquefied natural gas (LNG) and regional/sectoral demand growth for natural gas in Mexico.

[28] If a rapid or slow technology case is being run, this value is increased or decreased accordingly.

[29] Eastern Canada is expected to continue to provide only a small share of the total production in Canada and is almost exclusively offshore.

Assumptions for the growth rate of consumption (Appendix E, PEMEX_GFAC, IND_GFAC, ELE_GFAC, RC_GFAC) were based on the projections from the *International Energy Outlook 2010*. Assumptions about base level domestic production (PRD_GFAC) are based in part on the same source and analyst judgment. The production growth rate is adjusted using an additive factor based on the degree to which the average lower 48 wellhead price varies from a set base price, as follows:

$$\text{PRC_FAC} = MIN\left\{\left(\frac{OGWPRNG}{3.66}\right)^{0.03125} - 1, \quad 0.05\right\} \tag{40}$$

where,

PRC_FAC = Factor to add to assumed base level production growth rate (PRD_GFAC)

OGWPRNG = Lower 48 average natural gas wellhead price in the current forecast year (1987$/Mcf)

3.66 = Fixed base price, approximately equal to the average lower 48 natural gas wellhead price over the projection period based on *AEO2010* reference case results (1987$/Mcf), [set in the code and converted at $6.14 (2008$/Mcf)]

0.03125 = An assumed parameter

0.05 = Assumed minimum price factor

The volumes of LNG imported into Mexico for use in the country are initially set exogenously (Appendix E, MEXLNG). However, these values are scaled back if the projected total volumes available to North America (see below) are not sufficient to accommodate these levels. LNG imports into Baja destined for the U.S. are set endogenously with the LNG import volumes for the rest of North America, as discussed below. Finally, any excess supply in Mexico is assumed to be available for export to the United States, and any shortfall is assumed to be met by imports from the United States. [30]

Liquefied Natural Gas

LNG imports are set at the beginning of each NEMS iteration within the NGTDM by evaluating seasonal supply curves, based on outputs from EIA's International Natural Gas Model (INGM), at associated regasification tailgate prices set in the previous NEMS iteration. LNG exports from the lower 48 States are assumed to be zero for the forecast period. [31] LNG exports to Japan from Alaska are set exogenously by OGSM through Spring of 2013 when the Kenai Peninsula LNG plant's export license will expire. The NGTDM does not assume or project additional LNG exports from Alaska.[32] LNG import levels are established for each region, and period (peak and

[30]A minimum import level from Mexico is set exogenously (DEXP_FRMEX, Appendix E), as well as a maximum decline from historical levels for exports to Mexico (DFAC_TOMEX, Appendix E).

[31]The capability to project LNG exports in the model was not included in the *AEO2011* analysis largely due to resource constraints, which continue to be tight. While a very preliminary analysis was done using the International Natural Gas Model that showed the economic viability of a liquefaction project in the Gulf of Mexico to be questionable under preliminary reference case conditions, a more thorough analysis is warranted.

[32]TransCanada and ExxonMobil filed an open season plan for an Alaska Pipeline Project which includes an option for shipping

off-peak) The basic process is as follows for each NEMS iteration (except for the first step): 1) at the beginning of each forecast year set up LNG supply curves for eastern and western North America for each period (peak and off-peak), 2) using the supply curves and the quantity-weighted average regasification tailgate price from the previous NEMS iteration, determine the amount of LNG available for import into North America, 3) subtract the volumes that are exogenously set and dedicated to the Mexico market (unless they exceed the total), and 4) allocate the remaining amount to the associated LNG terminals using a share based on the regasification capacity, the volumes imported last year, and the relative prices.

The LNG import supply curves are developed off of a base price/quantity pair (Appendix E, LNGPPT, LNGQPT) from a reference case run of the INGM, using the same, or very similar, world oil price assumptions. The quantities equal the sum of the LNG imports into east or west North America in the associated period; and the prices equal the quantity-weighted average tailgate price at the regasification terminals. The mathematical specification of the curve is exactly like the one used for domestic production described earlier in this chapter, except the assumed elasticities are represented with different variables and have different values.[33] This representation represents a first cut at integrating the information from INGM in the domestic projections.[34] The formulation for these LNG supply curves will likely be revised in future NEMS to better capture the market dynamics as represented in the INGM.

Once the North American LNG import volumes are established, the exogenously specified LNG imports into Mexico are subtracted,[35] along with the sum of any assumed minimum level (Appendix E, LNGMIN) for each of the representative terminals in the U.S., Canada, and Baja, Mexico (as shown in **Table 2-1**). The remainder (TOTQ) is shared out to the terminals and then added to the terminal's assumed minimum import level to arrive at the final LNG import level by terminal and season. The shares are initially set as follows and then normalized to total to 1.0:

$$LSHR_{n,r} = \left\{ \frac{QLNGLAG_{n,r} - (LNGMIN_r * SH_{r,n})}{TOTQ_{n,c}} * PERQ + \frac{LNGCAP_r - LNGMIN_r}{TOTCAP_c} * (1 - PERQ) \right\} * \left\{ \frac{PLNG_{n,r}}{AVGPR_{n,c}} \right\}^{BETA} \quad (41)$$

where,

$LSHR_{n,r}$ = Initial share (before normalization) of LNG imports going to terminal r in period n from the east or west coast, fraction

$TOTQ_{n,c}$ = The level of LNG imports in the east or west coast to be shared out for a period n to the associated U.S. regasification regions

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gas to Valdez for export as LNG. Previous EIA analysis indicated that the option for a pipeline to the lower 48 States is likely to provide a greater netback to the producers and is therefore a more viable option. This analysis and model assumption will be reviewed in the future.

[33]For LNG the variables are called PARM_LNGxx, instead of PARM_SUPxx and are also traceable using Appendix E.

[34]As first implemented, the resulting LNG import volumes were somewhat erratic, so a five-year moving average was applied to the quantity inputs to smooth out the trajectory and more closely approximate a trend line.

[35]If the total available LNG import levels exceed the assumed LNG imports into Mexico, the volumes into Mexico are adjusted accordingly, not to be set below assumed minimums (Appendix E, MEXLNGMIN).

$QLNGLAG_{n,r}$ = LNG import level last year (Bcf)
$LNGMIN_r$ = Minimum annual LNG import level (Bcf) (Appendix E)
$SH_{r,n}$ = Fraction of LNG imported in period n last year
$LNGCAP_r$ = Beginning of year LNG sendout capacity[36] (Bcf) (Appendix E)
$TOTCAP_c$ = Total LNG sendout capacity on the east or west coast (Bcf)
PERQ = Assumed parameter (0.5)
$PLNG_{n,r}$ = Regasification tailgate price (1987$/Mcf)
$AVGPR_{n,r}$ = Average regasification tailgate price on the east or west coast (1987$/Mcf)
BETA = Assumed parameter (1.2)
r = Regasification terminal number (See Table 2-1)
n = Network or period (peak or off-peak)
c = East or west coast

Table 2-1. LNG Regasification Regions

Number	Regasification Terminal/Region
1	Everett, MA
2	Cove Point, MD
3	Elba Island, GA
4	Lake Charles, LA
5	New England
6	Middle Atlantic
7	South Atlantic
8	Florida/Bahamas

Number	Regasification Regions
9	Alabama/Mississippi
10	Louisiana/Texas
11	California
12	Washington/Oregon
13	Eastern Canada
14	Western Canada
15	Baja into the U.S.
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Source: Office of Integrated Analysis and Forecasting, U.S. Energy Information Administration

Alaska Natural Gas Routine

The NEMS demand modules provide a forecast of natural gas consumption for the total Pacific Census Division, which includes Alaska. Currently natural gas that is produced in Alaska cannot be transported to the lower 48 States via pipeline. Therefore, the production and consumption of natural gas in Alaska is handled separately within the NGTDM from the contiguous States. Annual estimates of contiguous Pacific Division consumption levels are derived within the NGTDM by first estimating Alaska natural gas consumption for all sectors, and then subtracting these from the core market consumption levels in the Pacific Division provided by the NEMS demand modules. The use of natural gas in compressed natural gas vehicles in Alaska is assumed to be negligible or nonexistent. The Electricity Market Module provides a value for

[36]Send-out capacity is the maximum annual volume of gas that can be delivered by a regasification facility into the pipeline.

natural gas consumption in Alaska by electric generators. The series of equations for specifying the consumption of gas by Alaska residential and commercial customers follows:

$$AK_RN_y = \exp\{-2.677 + (0.888 * \ln(AK_RN_{y-1})) - (0.185 * \ln(AK_RN_{y-2})) + (0.626 * \ln(AK_POP_y))\} \quad (42)$$

$$AK_CN_y = 0.932946 + (0.937471 * AK_CN_{y-1}) \quad (43)$$

$$(res): AKQTY_F_{s=1,y} = \{e^{(6.983794*(1-0.364042))} * (AKQTY_F_{s=1,y-1} * 1000)^{0.364042} * * AK_RN_y^{(0.601932*(1-0.364042))}\}/1000. \quad (44)$$

$$(com): AKQTY_F_{s=2,y} = \{e^{(9.425307*(1-0.736334))} * (AKQTY_F_{s=2,y-1} * 1000)^{0.736334} * AK_CN_y^{0.205020} * (AK_CN_{y-1} * 1000)^{(-0.736334*0.205020)}\}/1000. \quad (45)$$

where,

$AKQTY_F_{s=1}$ = consumption of natural gas by residential (s=1) customers in Alaska in year y (MMcf, converted to Bcf, Table F1, Appendix F1)

$AKQTY_F_{s=2}$ = consumption of natural gas by commercial (s=2) customers in Alaska in the current forecast year y (MMcf, converted to Bcf, Table F1, Appendix F1)

AK_RN = number of residential customers in year y (thousands, Table F1, Appendix F)

AK_CN_y = number of commercial customers in year y (thousands, Table F2, Appendix F)

AK_POP = exogenously specified projection of the population in Alaska (thousands, Appendix E)

Gas consumption by Alaska industrial customers is set exogenously, as follows:

$$(ind): AKQTY_F_{s=3,y} = AK_QIND_S_y \quad (46)$$

where,

$AKQTY_F_{s=3,y}$ = consumption of natural gas by industrial customers in year y (s=3), (Bcf)

AK_QIND_S = consumption of natural gas by industrial customers in southern Alaska (Bcf), the sum of consumption at the Agrium fertilizer plant (assumed to close in 2007, Appendix E) and at the Kenai LNG liquefaction facility (assumed to close in 2013, Appendix E)

s = sector

y = year

The production of gas in Alaska is basically set equal to the sum of the volumes consumed and transported out of Alaska, so depends on: 1) whether a pipeline is constructed from Alaska to

Alberta, 2) whether a gas-to-liquids plant is built in Alaska, and 3) consumption in and exports from Alaska. The production of gas related to the Alaska pipeline equals the volumes delivered to Alberta (which depend on assumptions about the pipeline capacity) plus what is consumed for related lease, plant, and pipeline operations (calculated as delivered volume divided by 1 minus the percent used for lease, plant, and pipeline operations). If the Petroleum Market Module (PMM) determines that a gas-to-liquids facility will be built in Alaska, then the natural gas consumed in the process (AKGTL_NGCNS, set in the PMM) is added to production in the north, along with the associated lease and plant fuel consumed. The production volumes related to the pipeline and the GTL plant are summed together ($N.AK_2$ below). Other production in North Alaska that is not related to the pipeline or GTL is largely lease and plant fuel associated with the crude oil extraction processes; whereas gas is produced in the south to satisfy consumption and export requirements. The quantity of lease and plant fuel not related to the pipeline or GTL in Alaska ($N.AK_1$ below) is assigned separately, includes lease and plant fuel used in the north and south, and is added to the other production ($N.AK_2$ below) to arrive at total North Alaska production. The details follow:

$$(S.AK):\ AK_PROD_{r=1} = AK_CONS_S + EXPJAP + QALK_LAP_S + QALK_PIP_S - AK_DISCR \quad (47)$$

$$(N.AK_1):\ AK_PROD_{r=2} = QALK_LAP_N = (0.0943884 * QALK_LAP_NLAG) + (0.038873 * \sum_{s=1}^{3} oOGPRCOAK_{s,y}) \quad (48)$$

$$(N.AK_2):\ AK_PROD_{r=3} = \frac{QAK_ALB_y}{1. - AK_PCTLSE_{r=3} - AK_PCTPLT_{r=3} - AK_PCTPIP_{r=3}} + AKGTL_NGCNS_t + AKGTL_LAP \quad (49)$$

where,

$$AK_CONS_S = \sum_{s=1}^{4} (AKQTY_F_s + AKQTY_I_s) \quad (50)$$

$$QALK_LAP_S = 0.0 \qquad \text{(total is assigned to the North)} \quad (51)$$

$$QALK_PIP_S = (AK_CONS_S + EXPJAP) * AK_PCTPIP_2 \quad (52)$$

$$AKGTL_LAP = oAKGTL_NGCNS_t * (AK_PCTLSE_3 + AK_PCTPLT_3) \quad (53)$$

where,

AK_PROD_r = dry gas production in Alaska (Bcf)
AK_CONS_S = total gas delivered to customers in South Alaska (Bcf)
$AKQTY_F_s$ = total gas delivered to core customers in Alaska in sector s (Bcf)
$AKQTY_I_s$ = total gas delivered to non-core customers in Alaska in sector s (Bcf)

EXPJAP	=	quantity of gas liquefied and exported to Japan (from OGSM in Bcf)
QALK_LAP_N	=	quantity of gas consumed in Alaska for lease and plant operations, excluding that related to the Alaska pipeline and GTL (Bcf)
QALK_LAP_NLAG	=	quantity of gas consumed for lease and plant operations in the previous year, excluding that related to the pipeline and GTL (Bcf)
$oOGPRCOAK_{s,y}$	=	crude oil production in Alaska by sector
$QALK_PIP_r$	=	quantity of gas consumed as pipeline fuel (Bcf)
AK_DISCR	=	discrepancy, the average (2006-2008) historically based difference in reported supply levels and consumption levels in Alaska (Bcf)
QAK_ALB_t	=	gas produced on North Slope entering Alberta via pipeline (Bcf)
AK_PCTLSE_r	=	(for r=1) not used, (for r=2) lease and plant consumption as a percent of gas consumption, (for r=3) lease consumption as a percent of gas production (fraction, Appendix E)
AK_PCTPLT_r	=	(for r=1 and r=2) not used, (for r=3) plant fuel as a percent of gas production (fraction, Appendix E)
AK_PCTPIP_r	=	(for r=1) not used, (for r=2) pipeline fuel as a percent of gas consumption, (for r=3) pipeline fuel as a percent of gas production (fraction, Appendix E)
$AKGTL_NGCNS_t$	=	natural gas consumed in a gas-to-liquids plant in the North Slope (from PMM in Bcf)
AKGTL_LAP	=	lease and plant consumption associated with the gas for a gas-to-liquids plant (Bcf)
s	=	sectors (1=residential, 2=commercial, 3=industrial, 4=transportation, 5=electric generators)
r	=	region (1 = south, 2 = north not associated with a pipeline to Alberta or gas-to-liquids process, 3 = north associated with a pipeline to Alberta and/or a gas-to-liquids plant

Lease, plant, and pipeline fuel consumption are calculated as follows. For south Alaska, the calculation of pipeline fuel (QALK_PIP_S) and lease and plant fuel (QALK_LAP_S) are shown above. For the Alaska pipeline, all three components are set to the associated production times the percentage of lease (AK_PCTLSE_3), plant (AK_PCTPLT_3), or pipeline fuel (AK_PCTPIP_3). For the gas-to-liquids process, lease and plant fuel (AKGTL_LAP) is calculated as shown above and pipeline fuel is considered negligible. For the rest of north Alaska, pipeline fuel consumption is assumed to be negligible, while lease and plant fuel not associated with the pipeline or GTL (QALK_LAP_N) is set based on an estimated equation shown previously (Table F10, Appendix F).

Estimates for natural gas wellhead and delivered prices in Alaska are estimated in the NGTDM for proper accounting, but have a very limited impact on the NEMS system. The average Alaska wellhead price (AK_WPRC) over the North and South regions (not accounting for the impact if a pipeline ultimately is connected to Alberta) is set using the following estimated equation:

$$AK_WPRC_1 = WPRLAG^{0.934077} * oIT_WOP_{y,1}^{(0.280960*(1-0.934077))} \quad (54)$$

where,

AK_WPRC_1 = natural gas wellhead price in Alaska, presuming no pipeline to Alberta (1987$/Mcf) (Table F1, Appendix F)
WPRLAG = AK_WPRC in the previous forecast year ($/Mcf)
$oIT_WOP_{y,1}$ = world oil price (1987$ per barrel)

The price for natural gas associated with a pipeline to Alberta is exogenously specified ($FR_PMINWPR_1$, Appendix E) and does not vary by forecast year. The average wellhead price for the State is calculated as the quantity-weighted average of AK_WPRC and $FR_PMINWPR_1$. Delivered prices in Alaska are set equal to the wellhead price (AK_WPRC) resulting from the equation above plus a fixed, exogenously specified markup (Appendix E -- AK_RM, AK_CM, AK_IN, AK_EM).

Within the model, the commencement of construction of the Alaska to Alberta pipeline is restricted to the years beyond an earliest start date (FR_PMINYR, Appendix E) and can only occur if a pipeline from the MacKenzie Delta to Alberta is not under construction. The same is true for the MacKenzie Delta pipeline relative to construction of the Alaska pipeline. Otherwise, the structural representation of the MacKenzie Delta pipeline is nearly identical to that of the Alaska pipeline, with different numerical values for model parameters. Therefore, the following description applies to both pipelines. Within the model the same variable names are used to specify the supporting data for the two pipelines, with an index of 1 for Alaska and an index of 2 for the MacKenzie Delta pipeline.

The decision to build a pipeline is triggered if the estimated cost to supply the gas to the lower 48 States is lower than an average of the lower 48 average wellhead price over the planning period of FR_PPLNYR (Appendix E) years.[37] Construction is assumed to take FR_PCNSYR (Appendix E) years. Initial pipeline capacity is assumed to accommodate a throughput delivered to Alberta of FR_PVOL (Appendix E). The first year of operation, the volume is assumed to be half of its ultimate throughput. If the trigger price exceeds the minimum price by FR_PADDTAR (Appendix E) after the initial pipeline is built, then the capacity will be expanded the following year by a fraction (FR_PEXPFAC, Appendix E) of the original capacity.

The expected cost to move the gas to the lower 48 is set as the sum of the wellhead price,[38] the charge for treating the gas, and the fuel costs (FR_PMINWPR, Appendix E), plus the pipeline tariff for moving the gas to Alberta and an assumed differential between the price in Alberta and the average lower 48 wellhead price (ALB_TO_L48, Appendix E). A risk premium is also included to largely reflect the expected initial price drop as a result of the introduction of the pipeline, as well as some of the uncertainties in the necessary capital outlays and in the ultimate

[37]The prices are weighted, with a greater emphasis on the prices in the recent past. An additional check is made that the estimated cost is lower than the lower 48 price in the last two years of the planning period and lower than a weighted average of the expected prices in the three years after the planning period, during the construction period.

[38]The required wellhead price in the MacKenzie Delta is progressively adjusted in response to changes in the U.S. national average drilling cost per well projections and across the forecast horizon in a higher or lower technology case, such that by the last year (2035) the price is higher or lower than the price in the reference case by a fraction equal to 0.25 times the technology factor adjustment rate (e.g., 0.50 for *AEO2011*).

selling price (FR_PRISK, Appendix E).[39] The cost-of-service based calculation for the pipeline tariff (NGFRPIPE_TAR) to move gas from each production source to Alberta is presented at the end of Chapter 6.

[39]If there is an annual decline in the average lower 48 wellhead price over the planning period for the Alaska pipeline, an additional adjustment is made to the expected cost (although it is not a cost item), equivalent to half of the drop in price averaged over the planning period, to account for the additional concern created by declining prices.

3. Overview of Solution Methodology

The previous chapter described the function of the NGTDM within the NEMS and the transformation and representation of supply and demand elements within the NGTDM. This chapter will present an overview of the NGTDM model structure and of the methodologies used to represent the natural gas transmission and distribution industries. First, a detailed description of the network used in the NGTDM to represent the U.S. natural gas pipeline system is presented. Next, a general description of the interrelationships between the submodules within the NGTDM is presented, along with an overview of the solution methodology used by each submodule.

NGTDM Regions and the Pipeline Flow Network

General Description of the NGTDM Network

In the NGTDM, a transmission and distribution network (**Figure 3-1**) simulates the interregional flow of gas in the contiguous United States and Canada in either the peak (December through March) or off-peak (April through November) period. This network is a simplified representation of the physical natural gas pipeline system and establishes the possible interregional transfers to move gas from supply sources to end-users. Each NGTDM region contains one transshipment node, a junction point representing flows coming into and out of the region. Nodes have also been defined at the Canadian and Mexican borders, as well as in eastern and western Canada. Arcs connecting the transshipment nodes are defined to represent flows between these nodes; and thus, to represent interregional flows. Each of these interregional arcs represents an aggregation of pipelines that are capable of moving gas from one region into another region. Bidirectional flows are allowed in cases where the aggregation includes some pipelines flowing one direction and other pipelines flowing in the opposite direction.[40] Bidirectional flows can also be the result of directional flow shifts within a single pipeline system due to seasonal variations in flows. Arcs leading from or to international borders generally[41] represent imports or exports. The arcs which are designated as "secondary" in **Figure 3-1** generally represent relatively low flow volumes and are handled somewhat differently and separately from those designated as "primary."

Flows are further represented by establishing arcs from the transshipment node to each demand sector/subregion represented in the NGTDM region. Demand in a particular NGTDM region can only be satisfied by gas flowing from that same region's transshipment node. Similarly, arcs are also established from supply points into transshipment nodes. The supply from each NGTDM/OGSM region is directly available to only one transshipment node, through which it must first pass if it is to be made available to the interstate market (at an adjoining transshipment

[40]Historically, one out of each pair of bidirectional arcs in Figure 3-1 represents a relatively small amount of gas flow during the year. These arcs are referred to as "the bidirectional arcs" and are identified as the secondary arcs in Figure 3-1, excluding 3 to 15, 5 to 10, 15 to E. Canada, 20 to 7, 21 to 11, 22 to 12, and Alaska to W. Canada. The flows along these arcs are initially set at the last historical level and are only increased (proportionately) when a known (or likely) planned capacity expansion occurs.

[41]Some natural gas flows across the Canadian border into the United States, only to flow back across the border without changing ownership or truly being imported. In addition, any natural gas that might flow from Alaska to the lower 48 states would cross the Canadian/U.S. border, but not be considered as an import.

node). During a peak period, one of the supply sources feeding into each transshipment node represents net storage withdrawals in the region during the peak period. Conversely during the off-peak period, one of the demand nodes represents net storage injections in the region during the off-peak period.

Figure 3-1. Natural Gas Transmission and Distribution Module Network

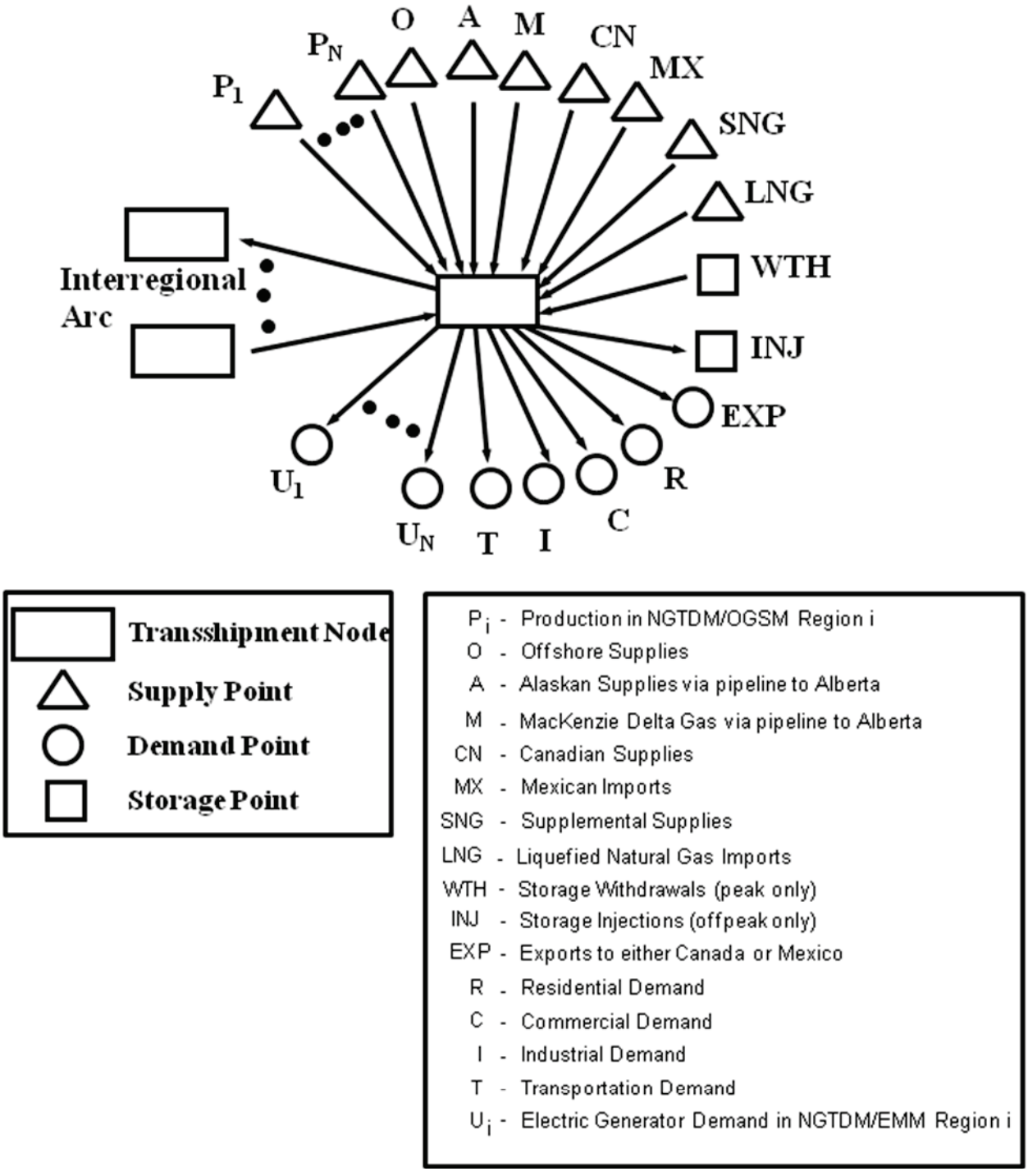


Figure 3-2 shows an illustration of all possible flows into and out of a transshipment node. Each transshipment node has one or more arcs to represent flows from or to other transshipment nodes. The transshipment node also has an arc representing flow to each end-use sector in the region (residential, commercial, industrial, electric generators, and transportation), including separate arcs to each electric generator subregion.[42] Exports and (in the off-peak period) net storage injections are also represented as flow out of a transshipment node. Each transshipment node can have one or more arcs flowing in from each supply source represented within the region. These supply points represent U.S. or Canadian onshore or U.S. offshore production,

[42]Conceptually within the model, the flow of gas to each end-use sector passes through a common city gate point before reaching the end-user.

liquefied natural gas imports, gas produced in Alaska and transported via pipeline, Mexican imports, (in the peak period) net storage withdrawals in the region, or supplemental gas supplies.

Figure 3-2. Transshipment Node



Two items accounted for but not presented in **Figure 3-2** are discrepancies or balancing items (i.e., average historically observed differences between independently reported natural gas supply and disposition levels (DISCR for the United States, CN_DISCR for Canada) and backstop supplies.[43]

Many of the types of supply listed above are relatively low in volume and are set independently of current prices and before the NGTDM determines a market equilibrium solution. As a result, these sources of supply are handled differently within the model. Structurally within the model only the price responsive sources of supply (i.e., onshore and offshore lower 48 U.S. production, Western Canadian Sedimentary Basin (WCSB) production, and storage withdrawals) are explicitly represented with supply nodes and connecting arcs to the transshipment nodes when the NGTDM is determining a market equilibrium solution.

Once the types of end-use destinations and supply sources into and out of each transshipment node are defined, a general network structure is created. Each transshipment node does not necessarily have all supply source types flowing in, or all demand source types flowing out. For instance, some transshipment nodes will have liquefied natural gas available while others will not. The specific end-use sectors and supply types specified for each transshipment node in the network are listed in **Table 3-1**. This table also provides the mapping of Electricity Market Module regions and Oil and Gas Supply Module regions to NGTDM regions (**Figure 2-3** and **Figure 2-5** in Chapter 2). The transshipment node numbers in the U.S. align with the NGTDM regions in **Figure 3-1**. Transshipment nodes 13 through 19 are pass-through nodes for the border crossings on the Canada/U.S. border, going from east to west.

As described earlier, the NGTDM determines the flow and price of natural gas in both a peak and off-peak period. The basic network structure separately represents the flow of gas during the two periods within the Interstate Transmission Submodule. Conceptually this can be thought of as two parallel networks, with three areas of overlap. First, pipeline expansion is determined only in the peak period network (with the exception of pipelines going into Florida from the East South Central Division). These levels are then used as constraints for pipeline flow in the off-peak period. Second, net withdrawals from storage in the peak period establish the net amount of natural gas that will be injected in the off-peak period, within a given forecast year. Similarly, the price of gas withdrawn in the peak period is the sum of the price of the gas when it was injected in the off-peak, plus an established storage tariff. Third, the supply curves provided by the Oil and Gas Supply Module are specified on an annual basis. Although, these curves are used to approximate peak and off-peak supply curves, the model is constrained to solve on the annual supply curve (i.e., when the annual curve is evaluated at the quantity-weighted average annual wellhead price, the resulting quantity should equal the sum of the production in the peak and off-peak periods). The details of how this is accomplished are provided in Chapter 4.

[43]Backstop supplies are allowed when the flow out of a transshipment node exceeds the maximum flow into a transshipment node. A high price is assigned to this supply source and it is generally expected not to be required (or desired). Chapter 4 provides a more detailed description of the setting and use of backstop supplies in the NGTDM.

Table 3-1. Demand and Supply Types at Each Transshipment Node in the Network

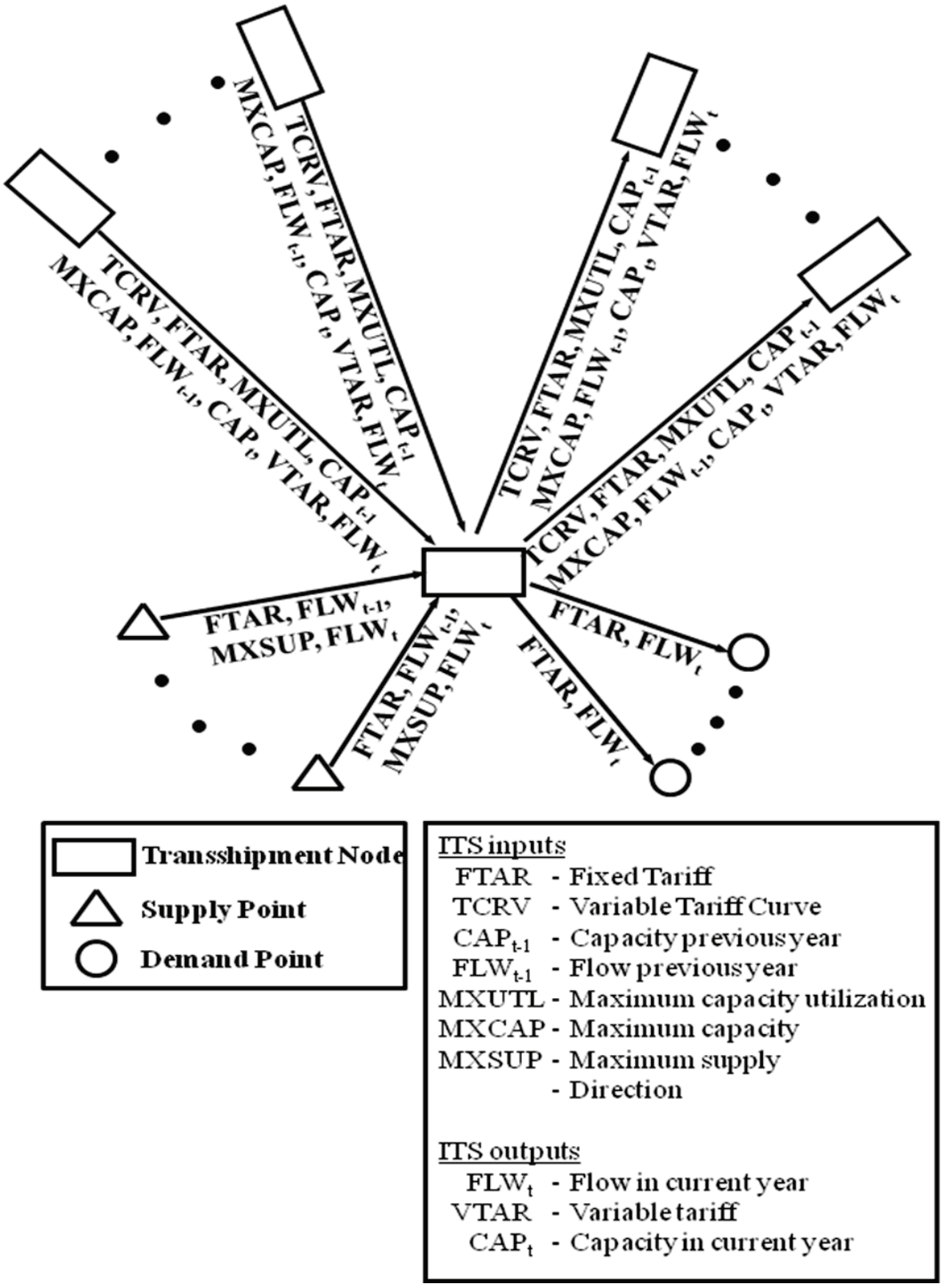
Transshipment Node	Demand Types	Supply Types
1	R, C, I, T, U(1)	P(1/1), LNG Everett Mass., LNG generic, SNG
2	R, C, I, T, U(2), INJ	P(2/1), WTH, LNG generic, SNG
3	R, C, I, T, U(3), U(4), INJ	P(3/1), WTH, SNG
4	R, C, I, T, U(5), INJ	P(4/3), P(4/5), SNG, WTH, LNG generic
5	R, C, I, T, U(6), U(7), INJ	P(5/1), LNG Cove Pt Maryland, LNG Elba Island Georgia, Atlantic Offshore, WTH, LNG generic, SNG
6	R, C, I, T, U(9), U(10), INJ	P(6/1), P(6/2), WTH, LNG generic, SNG
7	R, C, I, T, U(11), INJ	P(7/2), P(7/3), P(7/4), LNG Lake Charles Louisiana, Offshore Louisiana, Gulf of Mexico, WTH, LNG generic, SNG
8	R, C, I, T, U(12), U(13), INJ	P(8/5), WTH, SNG
9	R, C, I, T, U(15), INJ	P(9/6), WTH, LNG generic, SNG
10	R, C, I, T, U(6), U(8), INJ	P(10/2), WTH, SNG
11	R, C, I, T, U(14), INJ	P(11/4), P(11/5), WTH, SNG
12	R, C, I, T, U(16), INJ	P(12/6), Pacific Offshore, WTH, LNG generic, SNG
13 – 19	--	--
20	Mexican Exports (TX)	Mexican Imports (TX)
21	Mexican Exports (AZ/NM)	Mexican Imports (AZ/NM)
22	Mexican Exports (CA)	Mexican Imports (CA)
23	Eastern Canadian consumption, INJ	Eastern Canadian supply, WTH
24	Western Canadian consumption, INJ	Western Canadian supply, WTH, Alaskan Supply via a pipeline, MacKenzie Valley gas via a pipeline
P(x/y) – production in region defined in Figure 2-5 for NGTDM region x and OGSM region y U(z) – electric generator consumption in region z, defined in Figure 2-3		

Specifications of a Network Arc

Each arc of the network has associated variable inputs and outputs. The variables that define an interregional arc in the Interstate Transmission Submodule (ITS) are the pipeline direction, available capacity from the previous forecast year, the "fixed" tariffs and/or tariff curve, the flow on the arc from the previous year, the maximum capacity level, and the maximum utilization of the capacity (**Figure 3-3**). While a model solution is determined (i.e., the quantity of the natural gas flow along each interregional arc is determined), the "variable" or quantity dependent tariff and the required capacity to support the flow are also determined in the process.

For the peak period, the maximum capacity build levels are set to a factor above the 1990 levels. The factor is set high enough so that this constraint is rarely, if ever, binding. However, the structure could be used to limit growth along a particular path. In the off-peak period the maximum capacity levels are set to the capacity level determined in the peak period. The maximum utilization rate along each arc is used to capture the impact that varying demand loads over a season have on the utilization along an arc.

Figure 3-3. Variables Defined and Determined for Network Arc



For the peak period, the maximum utilization rate is calculated based on an estimate of the ratio of January-to-peak period consumption requirements. For the off-peak the maximum utilization rates are set exogenously (HOPUTZ, Appendix E). Capacity and flow levels from the previous forecast year are used as input to the solution algorithm for the current forecast year. In some cases, capacity that is newly available in the current forecast year will be exogenously set (PLANPCAP, Appendix E) as "planned" (i.e., highly probable that it will be built by the given forecast year based on project announcements). Any additional capacity beyond the planned level is determined during the solution process and is checked against maximum capacity levels and adjusted accordingly. Each of the interregional arcs has an associated "fixed" and "variable" tariff, to represent usage and reservation fees, respectively. The variable tariff is established by applying the flow level along the arc to the associated tariff supply curve, established by the Pipeline Tariff Submodule. During the solution process in the Interstate Transmission Submodule, the resulting tariff in the peak or off-peak period is added to the price at the source node to arrive at a price for the gas along the interregional arc right before it reaches its destination node. Through an iterative process, the relative values of these prices for all of the arcs entering a node are used as the basis for reevaluating the flow along each of these arcs.[44]

For the arcs from the transshipment nodes to the final delivery points, the variables defined are tariffs and flows (or consumption). The tariffs here represent the sum of several charges or adjustments, including interstate pipeline tariffs in the region, intrastate pipeline tariffs, and distributor markups. Associated with each of these arcs is the flow along the arc, which is equal to the amount of natural gas consumed by the represented sector. For arcs from supply points to transshipment nodes, the input variables are the production levels from the previous forecast year, a tariff, and the maximum limit on supplies or production. In this case the tariffs theoretically represent gathering charges, but are currently assumed to be zero.[45] Maximum supply levels are set at a percentage above a baseline or "expected" production level (described in Chapter 4). Although capacity limits can be set for the arcs to and from end-use sectors and supply points, respectively, the current version of the module does not impose such limits on the flows along these arcs.

Note that any of the above variables may have a value of zero, if appropriate. For instance, some pipeline arcs may be defined in the network that currently have zero capacity, yet where new capacity is expected in the future. On the other hand, some arcs such as those to end-use sectors are defined with infinite pipeline capacity because the model does not forecast limits on the flow of gas from transshipment nodes to end users.

Overview of the NGTDM Submodules and Their Interrelationships

The NEMS generates an annual forecast of the outlook for U.S. energy markets for the years 1990 through 2030. For the historical years, many of the modules in NEMS do not execute, but

[44]During the off-peak period in a previous version of the module, only the usage fee was used as a basis for determining the relative flow along the arcs entering a node. However, the total tariff was ultimately used when setting delivered prices.

[45]Ultimately the gathering charges are reflected in the delivered prices when the model is benchmarked to historically reported city gate prices.

simply assign historically published values to the model's output variables. The NGTDM similarly assigns historical values to most of the known module outputs for these years. However, some of the required outputs from the module are not known (e.g., the flow of natural gas between regions on a seasonal basis). Therefore, the model is run in a modified form to fill in such unknown, but required values. Through this process historical values are generated for the unknown parameters that are consistent with the known historically based values (e.g., the unknown seasonal interregional flows sum to the known annual totals).

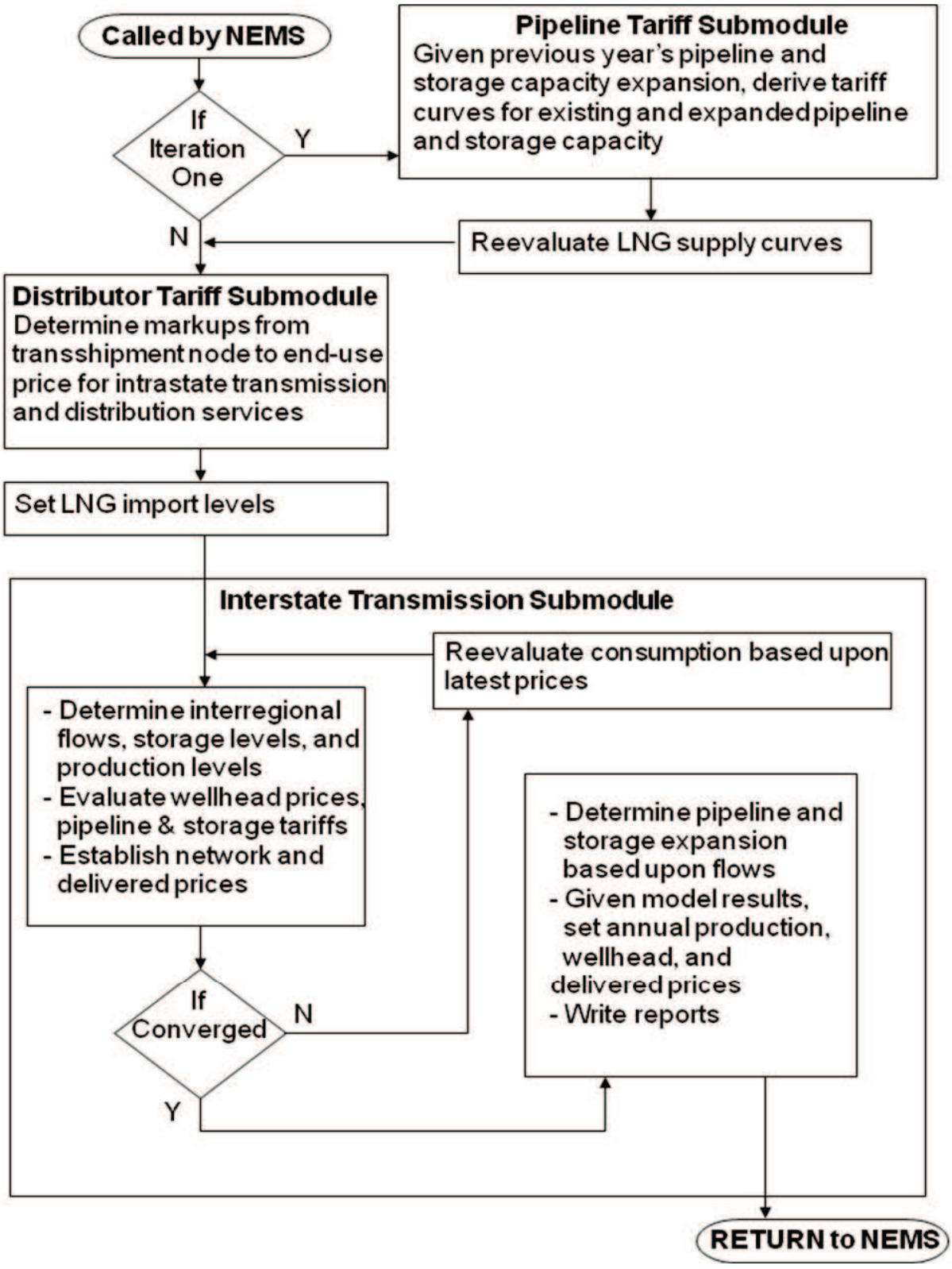
Although the NGTDM is executed for each iteration of each forecast year solved by the NEMS, it is not necessary that all of the individual components of the module be executed for all iterations. Of the NGTDM's three components or submodules, the Pipeline Tariff Submodule is executed only once per forecast year since the submodule's input values do not change from one iteration of NEMS to the next. However, the Interstate Transmission Submodule and the Distributor Tariff Submodule are executed during every iteration for each forecast year because their input values can change by iteration. Within the Interstate Transmission Submodule an iterative process is used. The basic solution algorithm is repeated multiple times until the resulting wellhead prices and production levels from one iteration are within a user-specified tolerance of the resulting values from the previous iteration, and equilibrium is reached. A process diagram of the NGTDM is provided in **Figure 3-4**, with the general calling sequence.

The Interstate Transmission Submodule is the primary submodule of the NGTDM. One of its functions is to forecast interregional pipeline and underground storage expansions and produce annual pipeline load profiles based on seasonal loads. Using this information from the previous forecast year and other data, the Pipeline Tariff Submodule uses an accounting process to derive revenue requirements for the current forecast year. This submodule builds pipeline and storage tariff curves based on these revenue requirements for use in the Interstate Transmission Submodule. These curves extend beyond the level of the current year's capacity and provide a means for assessing whether the demand for additional capacity, based on a higher tariff, is sufficient to warrant expansion of the capacity. The Distributor Tariff Submodule provides distributor tariffs for use in the Interstate Transmission Submodule. The Distributor Tariff Submodule must be called in each iteration because some of the distributor tariffs are based on consumption levels that may change from iteration to iteration. Finally, using the information provided by these other NGTDM submodules and other NEMS modules, the Interstate Transmission Submodule solves for natural gas prices and quantities that reflect a market equilibrium for the current forecast year. A brief summary of each of the NGTDM submodules follows.

Interstate Transmission Submodule

The Interstate Transmission Submodule (ITS) is the main integrating module of the NGTDM. One of its major functions is to simulate the natural gas price determination process. The ITS brings together the major economic factors that influence regional natural gas trade on a seasonal basis in the United States, the balancing of the demand for and the domestic supply of natural gas, including competition from imported natural gas. These are examined in combination with the relative prices associated with moving the gas from the producer to the end-user where and

Figure 3-4. NGTDM Process Diagram



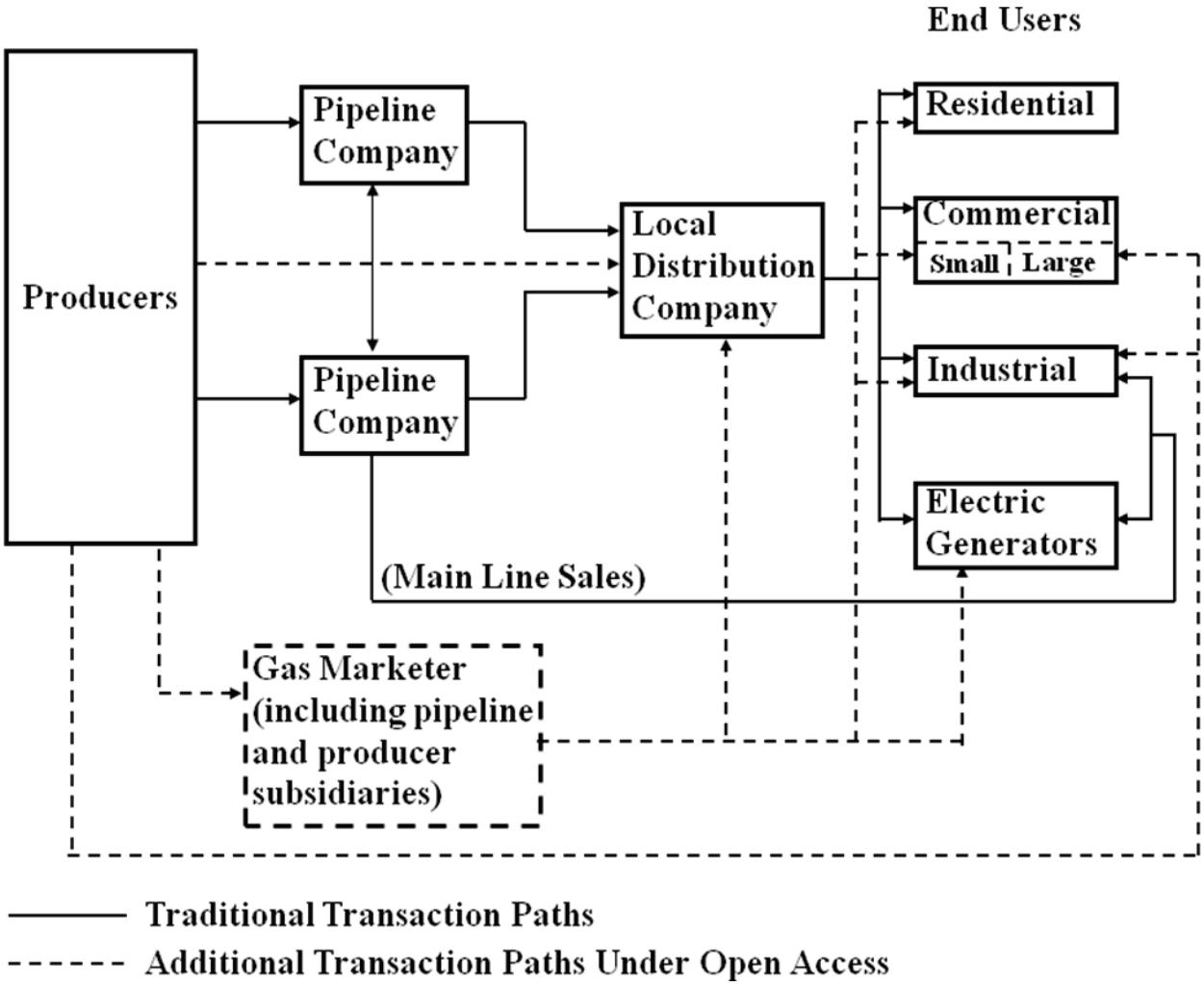
when (peak versus off-peak) it is needed. In the process, the ITS models the decision-making process for expanding pipeline and/or seasonal storage capacity in the U.S. gas market, determining the amount of pipeline and storage capacity to be added between or within regions in the NGTDM. Storage serves as the primary link between the two seasonal periods represented.

The ITS employs an iterative heuristic algorithm to establish a market equilibrium solution. Given the consumption levels from other NEMS modules, the basic process followed by the ITS involves first establishing the backward flow of natural gas in each period from the consumers, through the network, to the producers, based primarily on the relative prices offered for the gas (from the previous ITS iteration). This process is performed for the peak period first since the net withdrawals from storage during the peak period will establish the net injections during the off-peak period. Second, using the model's supply curves, wellhead prices are set corresponding to the desired production volumes. Also, using the pipeline and storage tariff curves from the Pipeline Tariff Submodule, pipeline and storage tariffs are set corresponding to the associated flow of gas, as determined in the first step. These prices are then translated from the producers, back through the network, to the city gate and the end-users, by adding the appropriate tariffs along the way. A regional storage tariff is added to the price of gas injected into storage in the off-peak to arrive at the price of the gas when withdrawn in the peak period. Delivered prices are derived for residential, commercial, electric generation, and transportation customers, as well as for both the core and non-core industrial sectors, using the distributor tariffs provided by the Distributor Tariff Submodule. At this point consumption levels can be reevaluated given the resulting set of delivered prices. Either way, the process is repeated until the solution has converged.

In the end, the ITS derives average seasonal (and ultimately annual) natural gas prices (wellhead, city gate, and delivered), and the associated production and flows, that reflect an interregional market equilibrium among the competing participants in the market. In the process of determining interregional flows and storage injections/withdrawals, the ITS also forecasts pipeline and storage capacity additions. In the calculations for the next forecast year, the Pipeline Tariff Submodule will adjust the requirements to account for the associated expansion costs. Other primary outputs of the module include lease, plant, and pipeline fuel use, Canadian import levels, and net storage withdrawals in the peak period.

The historical evolution of the price determination process simulated by the ITS is depicted schematically in **Figure 3-5**. At one point, the marketing chain was very straightforward, with end-users and local distribution companies contracting with pipeline companies, and the pipeline companies in turn contracting with producers. Prices typically reflected average costs of providing service plus some regulator-specified rate of return. Although this approach is still used as a basis for setting pipeline tariffs, more pricing flexibility has been introduced, particularly in the interstate pipeline industry and more recently by local distributors. Pipeline companies are also offering a range of services under competitive and market-based pricing arrangements. Additionally, newer players—for example marketers of spot gas and brokers for pipeline capacity—have entered the market, creating new links connecting suppliers with end-users. The marketing links are expected to become increasingly complex in the future.

Figure 3-5. Principal Buyer/Seller Transaction Paths for Natural Gas Marketing



The level of competition for pipeline services (generally a function of the number of pipelines having access to a customer and the amount of capacity available) drives the prices for interruptible transmission service and is having an effect on firm service prices. Currently, there are significant differences across regions in pipeline capacity utilization.[46] These regional differences are evolving as new pipeline capacity has been and is being constructed to relieve capacity constraints in the Northeast, to expand markets in the Midwest and the Southeast, and to move more gas out of the Rocky Mountain region and the Gulf of Mexico. As capacity changes take place, prices of services should adjust accordingly to reflect new market conditions.

[46]Further information can be found on the U.S. Energy Information Administration web page under "Pipeline Capacity and Usage" www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html.

Federal and State initiatives are reducing barriers to market entry and are encouraging the development of more competitive markets for pipeline and distribution services. Mechanisms used to make the transmission sector more competitive include the widespread capacity releasing programs, market-based rates, and the formation of market centers with deregulated upstream pipeline services. The ITS is not designed to model any specific type of program, but to simulate the overall impact of the movement towards market based pricing of transmission services.

Pipeline Tariff Submodule

The primary purpose of the Pipeline Tariff Submodule (PTS) is to provide volume dependent curves for computing tariffs for interstate transportation and storage services within the Interstate Transmission Submodule. These curves extend beyond current capacity levels and relate incremental pipeline or storage capacity expansion to corresponding estimated rates. The underlying basis for each tariff curve in the model is a forecast of the associated regulated revenue requirement. An accounting system is used to track costs and compute revenue requirements associated with both reservation and usage fees under a current typical regulated rate design. Other than an assortment of macroeconomic indicators, the primary input to the PTS from other modules/submodules in NEMS is the level of pipeline and storage capacity expansions in the previous forecast year. Once an expansion is projected to occur, the submodule calculates the resulting impact on the revenue requirement. The PTS currently assumes rolled-in (or average), not incremental rates for new capacity (i.e., the cost of any additional capacity is lumped in with the remaining costs of existing capacity when deriving a single tariff for all the customers along a pipeline segment).

Transportation revenue requirements (and associated tariff curves) are established for interregional arcs defined by the NGTDM network. These network tariff curves reflect an aggregation of the revenue requirements for individual pipeline companies represented by the network arc. Storage tariff curves are defined at regional NGTDM network nodes, and similarly reflect an aggregation of individual company storage revenue requirements. Note that these services are unbundled and do not include the price of gas, except for the cushion gas used to maintain minimum gas pressure. Furthermore, the submodule cannot address competition for pipeline or storage services along an aggregate arc or within an aggregate region, respectively. It should also be noted that the PTS deals only with the interstate market, and thus does not capture the impacts of State-specific regulations for intrastate pipelines. Intrastate transportation charges are accounted for within the Distributor Tariff Submodule.

Pipeline tariffs for transportation and storage services represent a more significant portion of the price of gas to industrial and electric generator end-users than to other sectors. Consumers of natural gas are grouped generally into two categories: (1) those that need firm or guaranteed service because gas is their only fuel option or because they are willing to pay for security of supply, and (2) those that do not need guaranteed service because they can either periodically terminate operations or use fuels other than natural gas. The first group of customers (core customers) is assumed to purchase firm transportation services, while the latter group (non-core customers) is assumed to purchase non-firm service (e.g., interruptible service, released capacity). Pipeline companies guarantee to their core customers that they will provide peak day

service up to the maximum capacity specified under their contracts even though these customers may not actually request transport of gas on any given day. In return for this service guarantee, these customers pay monthly reservation fees (or demand charges). These reservation fees are paid in addition to charges for transportation service based on the quantity of gas actually transported (usage fees or commodity charges). The pipeline tariff curves generated by the PTS are used within the ITS when determining the relative cost of purchasing and moving gas from one source versus another in the peak and off-peak seasons. They are also used when setting the price of gas along the NGTDM network and ultimately to the end-users.

The actual rates or tariffs that pipelines are allowed to charge are largely regulated by the Federal Energy Regulatory Commission (FERC). FERC's ratemaking traditionally allows (but does not necessarily guarantee) a pipeline company to recover its costs, including what the regulators consider a fair rate of return on capital. Furthermore, FERC not only has jurisdiction over how cost components are allocated to reservation and usage categories, but also how reservation and usage costs are allocated across the various classes of transmission (or storage) services offered (e.g., firm versus non-firm service). Previous versions of the NGTDM (and therefore the PTS) included representations of natural gas moved (or stored) using firm and non-firm service. However, in an effort to simplify the module, this distinction has been removed in favor of moving from an annual to a seasonal model. The impact of the distinction of firm versus non-firm service on core and non-core delivered prices is indirectly captured in the markup established in the Distributor Tariff Submodule. More recent initiatives by FERC have allowed for more flexible processes for setting rates when a service provider can adequately demonstrate that it does not possess significant market power. The use of volume dependent tariff curves partially serves to capture the impact of alternate rate setting mechanisms. Additionally, various rate making policy options discussed by FERC would allow peak-season rates to rise substantially above the 100-percent load factor rate (also known as the full cost-of-service rate). In capacity-constrained markets, the basis differential between markets connected via the constrained pipeline route will generally be above the full cost of service pipeline rates. The NGTDM's ultimate purpose is to project market prices; it uses cost-of-service rates as a means in the process of establishing market prices.

Distributor Tariff Submodule

The primary purpose of the Distributor Tariff Submodule (DTS) is to determine the price markup from the regional market hub to the end-user. For most customers, this consists of (1) distributor markups charged by local distribution companies for the distribution of natural gas from the city gate to the end user and (2) markups charged by intrastate pipeline companies for intrastate transportation services. Intrastate pipeline tariffs are specified exogenously to the model and are currently set to zero (INTRAST_TAR, Appendix E). However, these tariffs are accounted for in the module indirectly. For most industrial and electric generator customers, gas is not purchased through a local distribution company, so they are not specifically charged a distributor tariff. In this case, the "distributor tariff" represents the difference between the average price paid by local distribution companies at the city gate and the price paid by the average industrial or electric generator customer. Distributor tariffs are distinguished within the DTS by sector (residential, commercial, industrial, transportation, and electric generator), region (NGTDM/EMM regions

for electric generators and NGTDM regions for the rest), seasons (peak or off-peak), and as appropriate by service type or class (core or non-core).

Distribution markups represent a significant portion of the price of gas to residential, commercial, and transportation customers, and less so to the industrial and electric generation sectors. Each sector has different distribution service requirements, and frequently different transportation needs. For example, the core customers in the model (residential, transportation, commercial and some industrial and electric generator customers) are assumed to require guaranteed on-demand (firm) service because natural gas is largely their only fuel option. In contrast, large portions of the industrial and electric generator sectors may not rely solely on guaranteed service because they can either periodically terminate operations or switch to other fuels. These customers are referred to as non-core. They can elect to receive some gas supplies through a lower priority (and lower cost) interruptible transportation service. While not specifically represented in the model, during periods of peak demand, services to these sectors can be interrupted in order to meet the natural gas requirements of core customers. In addition, these customers frequently select to bypass the local distribution company pipelines and hook up directly to interstate or intrastate pipelines.

The rates that local distribution companies and intrastate carriers are allowed to charge are regulated by State authorities. State ratemaking traditionally allows (but does not necessarily guarantee) local distribution companies and intrastate carriers to recover their costs, including what the regulators consider a fair return on capital. These rates are derived from the cost of providing service to the end-use customer. The State authority determines which expenses can be passed through to customers and establishes an allowed rate of return. These measures provide the basis for distinguishing rate differences among customer classes and type of service by allocating costs to these classes and services based on a rate design. The DTS does not project distributor tariffs through a rate base calculation as is done in the PTS, partially due to limits on data availability.[47] In most cases, projected distributor tariffs in the model depend initially on base year values, which are established by subtracting historical city gate prices from historical delivered prices, and generally reflect an average over recent historical years.

Distributor tariffs for all but the transportation sector are set using econometrically estimated equations.[48] Transportation sector markups, representing sales for natural gas vehicles, are set separately for fleet and personal vehicles and account for distribution to delivery stations, retail markups, and federal and state motor fuels taxes. In addition, the NGTDM assesses the potential construction of infrastructure to support fueling compressed natural gas vehicles.

[47] In theory these cost components could be compiled from rate filings to state Public Utility Commissions; however, such an extensive data collection effort is beyond the available resources.

[48] An econometric approach was used largely as a result of data limitations. EIA data surveys do not collect the cost components required to derive revenue requirements and cost-of-service for local distribution companies and intrastate carriers. These cost components can be compiled from rate filings to Public Utility Commissions; however, an extensive data collection effort is beyond the scope of NEMS at this time.

4. Interstate Transmission Submodule Solution Methodology

As a key component of the NGTDM, the Interstate Transmission Submodule (ITS) determines the market equilibrium between supply and demand of natural gas within the North American pipeline system. This translates into finding the price such that the quantity of gas that consumers would desire to purchase equals the quantity that producers would be willing to sell, accounting for the transmission and distribution costs, pipeline fuel use, capacity expansion costs and limitations, and mass balances. To accomplish this, two seasonal periods were represented within the module--a peak and an off-peak period. The network structures within each period consist of an identical system of pipelines, and are connected through common supply sources and storage nodes. Thus, two interconnected networks (peak and off-peak) serve as the framework for processing key inputs and balancing the market to generate the desired outputs. A heuristic approach is used to systematically move through the two networks solving for production levels, network flows, pipeline and storage capacity requirements,[49] supply and citygate prices, and ultimately delivered prices until mass balance and convergence are achieved. (The methodology used for calculating distributor tariffs is presented in Chapter 5.) Primary input requirements include seasonal consumption levels, capacity expansion cost curves, annual natural gas supply levels and/or curves, a representation of pipeline and storage tariffs, as well as values for pipeline and storage starting capacities, and network flows and prices from the previous year. Some of the inputs are provided by other NEMS modules, some are exogenously defined and provided in input files, and others are generated by the module in previous years or iterations and used as starting values. Wellhead, import, and delivered prices, supply quantities, and resulting flow patterns are obtained as output from the ITS and sent to other NGTDM submodules or other NEMS modules after some processing. Network characteristics, input requirements, and the heuristic process are presented more fully below.

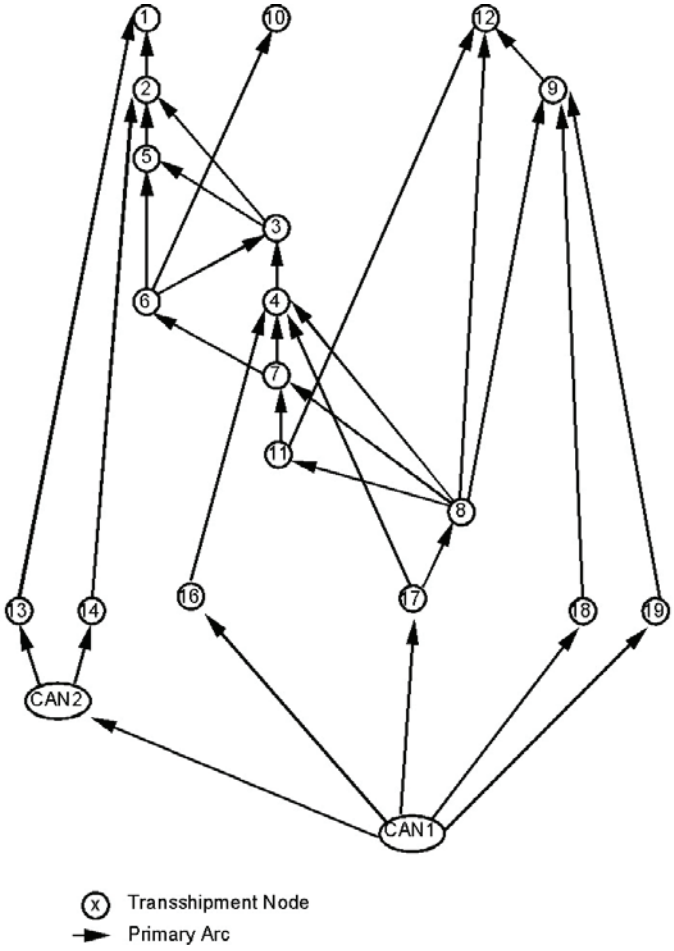
Network Characteristics in the ITS

As described in an earlier chapter, the NGTDM network consists of 12 NGTDM regions (or transshipment nodes) in the lower 48 states, three Mexican border crossing nodes, seven Canadian border crossing nodes, and two Canadian supply/demand regions. Interregional arcs connecting the nodes represent an aggregation of pipelines that are capable of moving gas from one region (or transshipment node) into another. These arcs have been classified as either primary flow arcs or secondary flow arcs. The primary flow arcs (see **Figure 3-1**) represent major flow corridors for the transmission of natural gas. Secondary arcs represent either flow in the opposite direction from the primary flow (historically about 3 percent of the total flow) or relatively low flow volumes that are set exogenously or outside the ITS equilibration routine (e.g. Mexican imports and exports). In the ITS, this North American natural gas pipeline flow network has been restructured into a hierarchical, acyclic network representing just the primary flow of natural gas (**Figure 4-1**). The representation of flows along secondary arcs is described in the Solution Process section below. A hierarchical, acyclic network structure allows for the

[49]In reality, capacity expansion decisions are made based on expectations of future demand requirements, allowing for regulatory approvals and construction lead times. In the model, additional capacity is available immediately, once it is determined that it is needed. The implicit assumption is that decision makers exercised perfect foresight and that planning and construction for the pipeline actually started before the pipeline came online.

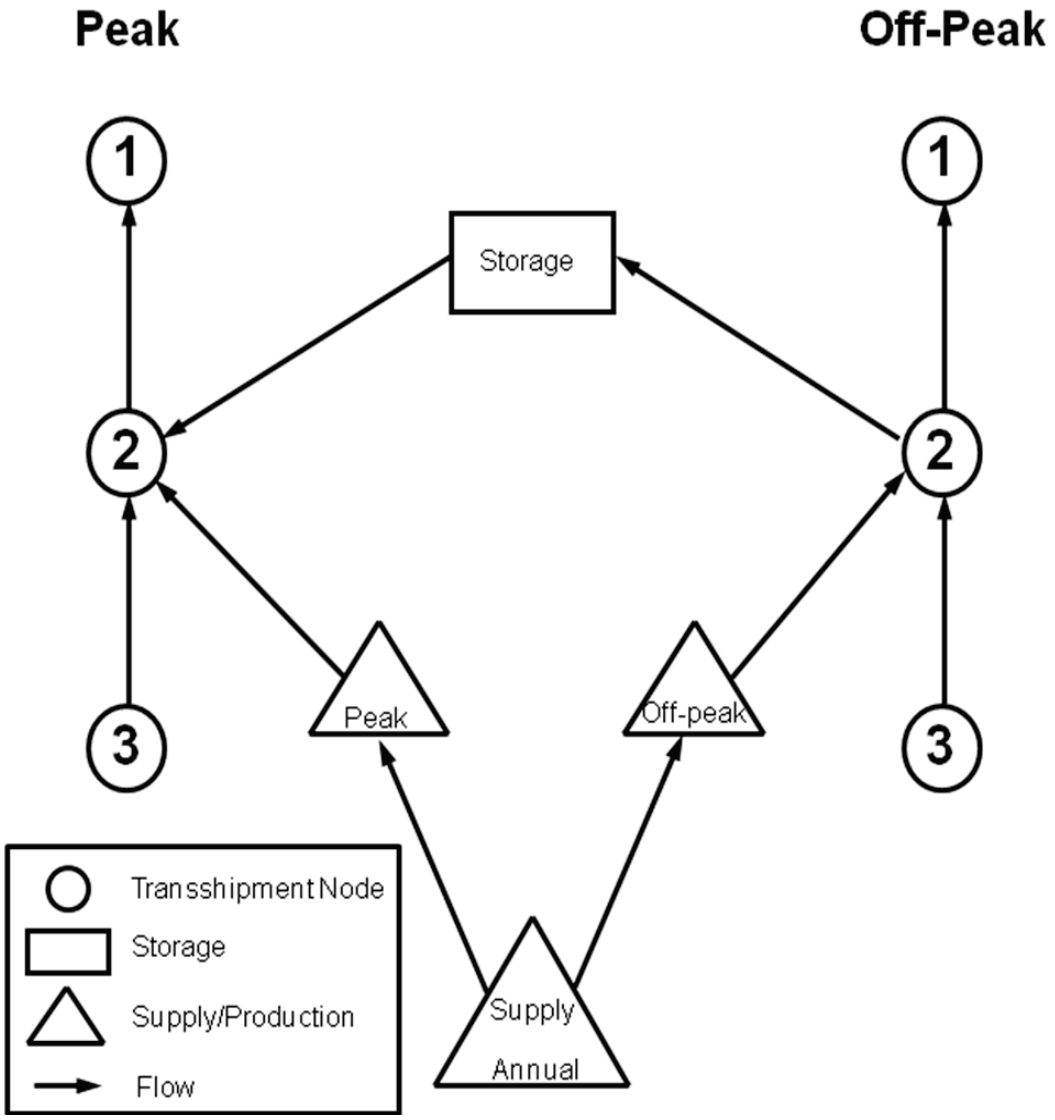
systematic representation of the flow of natural gas (and its associated prices) from the supply sources, represented towards the bottom of the network, up through the network to the end-use consumer at the upper end of the network.

Figure 4-1. Network "Tree" of Hierarchical, Acyclic Network of Primary Arcs



In the ITS, two interconnected acyclic networks are used to represent natural gas flow to end-use markets during the peak period (PK) and flow to end-use markets during the off-peak period (OP). These networks are connected regionally through common supply sources and storage nodes (**Figure 4-2**). Storage within the module only represents the transfer of natural gas produced in the off-peak period to meet the higher demands in the peak period. Therefore, net storage injections are included only in the off-peak period, while net storage withdrawals occur only in the peak period. Within a given forecast year, the withdrawal level from storage in the peak period establishes the level of gas injected in the off-peak period. Annual supply sources provide natural gas to both networks based on the combined network production requirements and corresponding annual supply availability in each region.

Figure 4-2. Simplified Example of Supply and Storage Links Across Networks



Input Requirements of the ITS

The following is a list of the key inputs required during ITS processing:

- Seasonal end-use consumption or demand curves for each NGTDM region and Canada
- Seasonal imports (except Canada) and exports by border crossing
- Canadian import capacities by border crossing
- Total natural gas production in eastern Canada and unconventional production in western Canada, by season.
- Natural gas flow by pipeline from Alaska to Alberta.
- Natural gas flow by pipeline from the MacKenzie Delta to Alberta.

- Regional supply curve parameters for U.S. nonassociated and western Canadian conventional natural gas supply[50]
- Seasonal supply quantities for U.S. associated-dissolved gas, synthetic gas, and other supplemental supplies by NGTDM region
- Seasonal network flow patterns from the previous year, by arc (including flows from storage, variable supply sources, and pipeline arcs)
- Seasonal network prices from the previous year, by arc (including flows from storage, variable supply sources, and pipeline arcs)
- Pipeline capacities, by arc
- Seasonal maximum pipeline utilizations, by arc
- Seasonal pipeline (and storage) tariffs representing variable costs or usage fees, by arc (and region)
- Pipeline capacity expansion/tariff curves for the peak network, by arc
- Storage capacity expansion/tariff curves for the peak network, by region
- Seasonal distributor tariffs by sector and region

Many of the inputs are provided by other NEMS submodules, some are defined from data within the ITS, and others are ITS model results from operation in the previous year. For example, supply curve parameters for lower 48 nonassociated onshore and offshore natural gas production and lower 48 associated-dissolved gas production are provided by the Oil and Gas Supply Module (OGSM). In contrast, Canadian data are set within the NGTDM as direct input to the ITS. U.S. end-use consumption levels are provided by NEMS demand modules; pipeline and storage capacity expansion/tariff curve parameters are provided by the Pipeline Tariff Submodule (PTS, see chapter 6); and seasonal distributor tariffs are defined by the Distributor Tariff Submodule (DTS, see Chapter 5). Seasonal network flow patterns and prices are determined within the ITS. They are initially set based on historical data, and then from model results in the previous model year.

Because the ITS is a seasonal model, most of the input requirements are on a seasonal level. In most cases, however, the information provided is not represented in the form defined above and needs to be processed into the required form. For example, regional end-use consumption levels are initially defined by sector on an annual basis. The ITS disaggregates each of these sector-specific quantities into a seasonal peak and off-peak representation, and then aggregates across sectors within each season to set a total consumption level. Also, regional fixed supplies and some of the import/export levels represent annual values. A simple methodology has been developed to disaggregate the annual information into peak and off-peak quantities using item-specific peak sharing factors (e.g., PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, PKSHR_SUPLM, PKSHR_ILNG, and PKSHR_YR). For more detail on these inputs see Chapter 2. A similar method is used to approximate the consumption and supply in the peak month of each period. This information is used to verify that sufficient sustained[51] capacity is available for the peak day in each period; and if not, it is used as a basis for adding

[50]These supply sources are referred to as the "variable" supplies because they are allowed to change in response to price changes during the ITS solution process. A few of the "fixed" supplies are adjusted each NEMS iteration, generally in response to price, but are held constant within the ITS solution process.

[51]"Sustained" capacity refers to levels that can operationally be sustained throughout the year, as opposed to "peak" capacity which can be realized at high pressures and would not generally be maintained other than at peak demand periods.

additional capacity. The assumption reflected in the model is that, if there is sufficient sustained capacity to handle the peak month, line packing[52] and propane injection can be used to accommodate a peak day in this month.

Heuristic Process

The basic process used to determine supply and delivered prices in the ITS involves starting from the top of the hierarchical, acyclic network or "tree" (as shown in **Figure 4-1**) with end-use consumption levels, systematically moving down each network (in the opposite direction from the primary flow of gas) to define seasonal flows along network arcs that will satisfy the consumption, evaluating wellhead prices for the desired production levels, and then moving up each network (in the direction of the primary flow of gas) to define transmission, node, storage, and delivered prices.

While progressively moving down the peak or off-peak network, net regional demands are assigned for each node on each network. Net regional demands are defined as the sum of consumption in the region plus the gas that is exiting the region to satisfy consumption elsewhere, net of fixed[53] supplies in the region. The consumption categories represented in net regional demands include end-use consumption in the region, exports, pipeline fuel consumption, secondary and primary flows out of the region, and for the off-peak period, net injections into regional storage facilities. Regional fixed supplies include imports (except conventional gas from Western Canada), secondary flows into the region, and the regions associated-dissolved production, supplemental supplies, and other fixed supplies. The net regional demands at a node will be satisfied by the gas flowing along the primary arcs into the node, the local "variable" supply flowing into the node, and for the peak period, the gas withdrawn from the regional storage facilities on a net basis.

Starting with the node(s) at the top of the network tree (i.e., nodes 1, 10, and 12 in **Figure 4-1**), the model uses a sharing algorithm to determine the percent of the represented region's net demand that is satisfied by each arc going into the node. The resulting shares are used to define flows along each arc (supply, storage, and interregional pipeline) into the region (or node). The interregional flows then become additional consumption requirements (i.e., primary flows out of a region) at the corresponding source node (region). If the arc going into the original node is from a supply or storage[54] source, then the flow represents the production or storage withdrawal level, respectively. The sharing algorithm is systematically applied (going down the network tree) to each regional node until flows have been defined for all arcs along a network, such that consumption in each region is satisfied.

Once flows are established for each network (and pipeline tariffs are set by applying the flow levels to the pipeline tariff curves), resulting production levels for the variable supplies are used to determine regional wellhead prices and, ultimately, storage, node, and delivered prices. By

[52]Line packing is a means of storing gas within a pipeline for a short period of time by compressing the gas.

[53]Fixed supplies are those supply sources that are not allowed to vary in response to changes in the natural gas price during the ITS solution process.

[54]For the peak period networks only.

systematically moving up each network tree, regional wellhead prices are used with pipeline tariffs, while adjusting for price impacts from pipeline fuel consumption, to calculate regional node prices for each season. Next, intraregional and intrastate markups are added to the regional/seasonal node prices, followed by the addition of corresponding seasonal, sectoral distributor tariffs, to generate delivered prices. Seasonal prices are then converted to annual delivered prices using quantity-weighted averaging. To speed overall NEMS convergence,[55] the delivered prices can be applied to representative demand curves to approximate the demand response to a change in the price and to generate a new set of consumption levels. This process of going up and down the network tree is repeated until convergence is reached.

The order in which the networks are solved differs depending on whether movement is down or up the network tree. When proceeding down the network trees, the peak network flows are established first, followed by the off-peak network flows. This order has been established for two reasons. First, capacity expansion is decided based on peak flow requirements.[56] This in turn is used to define the upper limits on flows along arcs in the off-peak network. Second, net storage injections (represented as consumption) in the off-peak season cannot be defined until net storage withdrawals (represented as supplies) in the peak season are established. When going up the network trees, prices are determined for the off-peak network first, followed by the peak network. This order has been established mainly because the price of fuel withdrawn from storage in the peak season is based on the cost of fuel injected into storage in the off-peak season plus a storage tariff.

If net demands exceed available supplies on a network in a region, then a backstop supply is made available at a higher price than other local supply. The higher price is passed up the network tree to discourage (or decrease) demands from being met via this supply route. Thus, network flows respond by shifting away from the backstop region until backstop supply is no longer needed.

Movement down and up each network tree (defined as a cycle) continues within a NEMS iteration until the ITS converges. Convergence is achieved when the regional seasonal supply prices determined during the current cycle down the network tree are within a designated minimum percentage tolerance from the supply prices established the previous cycle down the network tree. In addition, the absolute change in production between cycles within supply regions with relatively small production levels are checked in establishing convergence. In addition, the presence of backstop will prevent convergence from being declared. Once convergence is achieved, only one last movement up each network tree is required to define final regional/seasonal node and delivered prices. If convergence is not achieved, then a set of "relaxed" supply prices is determined by weighting regional production results from both the current and the previous cycle down the network tree, and obtaining corresponding new annual and seasonal supply prices from the supply curves in each region based on these "relaxed" production levels. The concept of "relaxation" is a means of speeding convergence by solving

[55]At various times, NEMS has not readily converged and various approaches have been taken to improve the process. If the NGTDM can anticipate the potential demand response to a price change from one iteration to the next, and accordingly moderate the price change, the NEMS will theoretically converge to an equilibrium solution in less iterations.

[56]Pipeline capacity into region 10 (Florida) is allowed to expand in either the peak or off-peak period because the region experiences its peak usage of natural gas in what is generally the off-peak period for consumption in the rest of the country.

for quantities (or prices) in the current iteration based on a weighted-average of the prices (or quantities) from the previous two iterations, rather than just using the previous iteration's values.[57]

The following subsections describe many of these procedures in greater detail, including: net node demands, pipeline fuel consumption, sharing algorithm, wellhead prices, tariffs, arc, node, and storage prices, backstop, convergence, and delivered and import prices. A simple flow diagram of the overall process is presented in **Figure 4-3**.

Net Node Demands

Seasonal net demands at a node are defined as total seasonal demands in the region, net of seasonal fixed supplies entering the region. Regional demands consist of primary flows exiting the region (including net storage injections in the off-peak), pipeline fuel consumption, end-use consumption, discrepancies (or historical balancing item), Canadian consumption, exports, and other secondary flows exiting the region. Fixed supplies include associated-dissolved gas, Alaskan gas supplies to Alberta, synthetic natural gas, other supplemental supplies, LNG imports, fixed Canadian supplies (including MacKenzie Delta gas), and other secondary flows entering the region. Seasonal net node demands are represented by the following equations:

Peak:

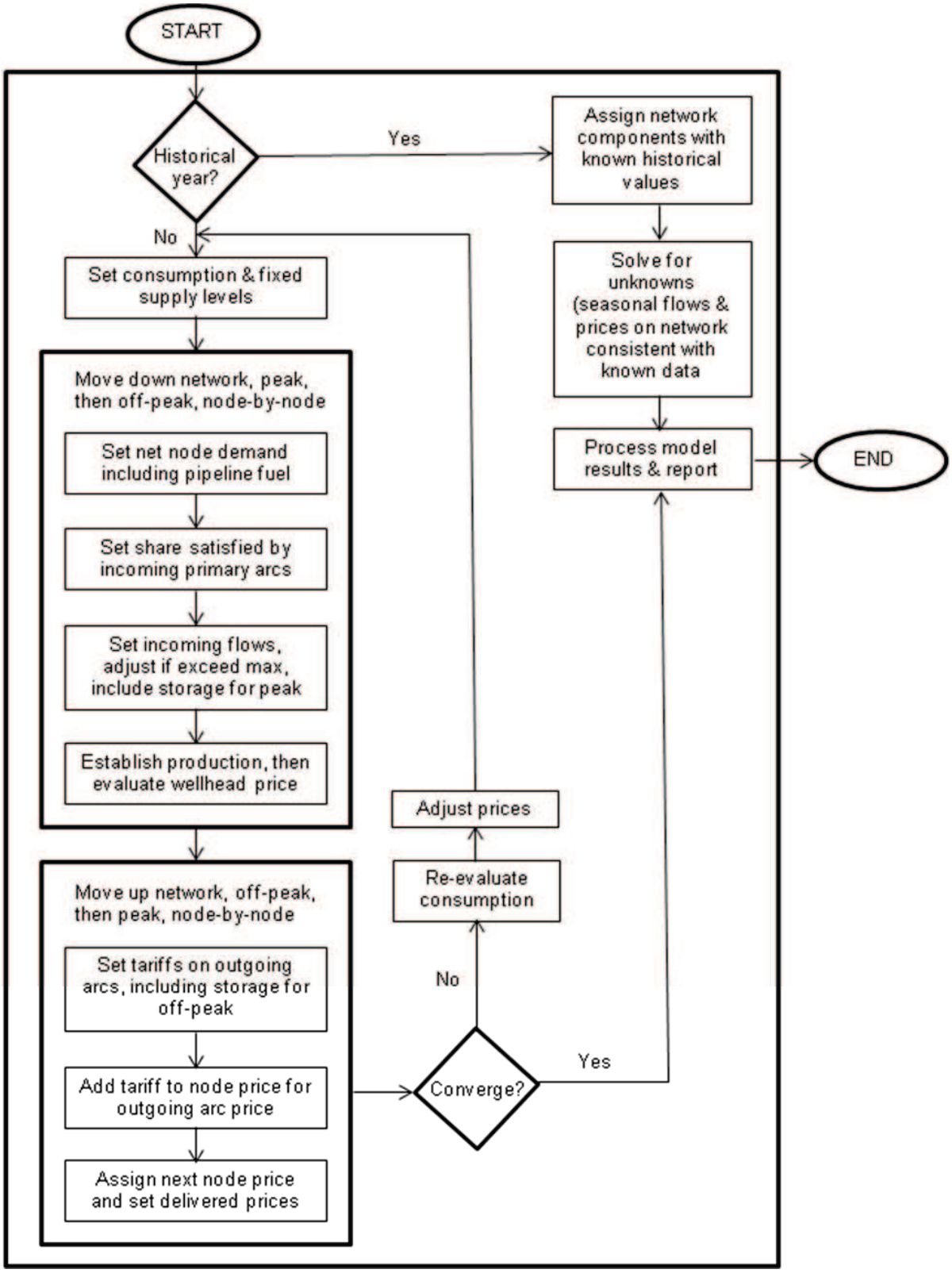
$$\begin{aligned} NODE_DMD_{PK,r} &= PFUEL_{PK,r} + FLOW_{PK,a} + NODE_CDMD_{PK,r} \\ &\sum_{nonu} (PKSHR_DMD_{nonu,r} * (ZNGQTY_F_{nonu,r} + ZNGQTY_I_{nonu,r})) + \\ &\sum_{jutil \subset r} (PKSHR_UDMD_{jutil} * (ZNGUQTY_F_{jutil} + ZNGUQTY_I_{jutil}) \end{aligned} \quad (55)$$

$$\begin{aligned} NODE_CDMD_{PK,r} = YEAR_CDMD_{PK,r} &- (PKSHR_PROD_s * ZADGPRD_s) - \\ &(PKSHR_ILNG * OGQNGIMP_{L,t}) \end{aligned} \quad (56)$$

$$\begin{aligned} YEAR_CDMD_{PK,r} = DISCR_{PK,r,t} &+ CN_DISCR_{PK,cn} \\ &((PKSHR_CDMD) * CN_DMD_{cn,r}) + \\ &(PK1 * SAFLOW_{a,t}) - (PK2 * SAFLOW_{a',t}) - \\ &(PKSHR_YR * QAK_ALB_t) - (PKSHR_SUPLM * ZTOTSUP_r) - \\ &(PKSHR_PROD_s * CN_FIXSUP_{cn,t}) \end{aligned} \quad (57)$$

[57]The model typically solves within 3 to 6 cycles.

Figure 4-3. Interstate Transmission Submodule System



Off-Peak:

$$NODE_DMD_{OP,r} = PFUEL_{OP,r} + FLOW_{OP,a} + FLOW_{PK,st} + NODE_CDMD_{OP,r} +$$
$$\sum_{nonu}((1 - PKSHR_DMD_{nonu,r}) * (ZNGQTY_F_{nonu,r} + ZNGQTY_I_{nonu,r})) +$$
$$\sum_{jutil \subset r}((1 - PKSHR_UDMD_{jutil}) * (ZNGUQTY_F_{jutil} + ZNGUQTY_I_{jutil})) + \quad (58)$$

$$NODE_CDMD_{OP,r} = YEAR_CDMD_{OP,r} - ((1 - PKSHR_PROD_s) * ZADGPRD_s) -$$
$$((1 - PKSHR_ILNG) * OGQNGIMP_{L,t}) \quad (59)$$

$$YEAR_CDMD_{OP,r} = DISCR_{OP,r,t} + CN_DISCR_{OP,cn} +$$
$$((1 - PKSHR_CDMD) * CN_DMD_{cn,r}) +$$
$$((1 - PK1) * SAFLOW_{a,t}) - ((1 - PK2) * SAFLOW_{a',t}) -$$
$$((1 - PKSHR_YR) * QAK_ALB_t) - \quad (60)$$
$$((1 - PKSHR_SUPLM) * ZTOTSUP_r) -$$
$$((1 - PKSHR_PROD_s) * CN_FIXSUP_{cn,t})$$

where,

$NODE_DMD_{n,r}$ = net node demands in region r, for network n (Bcf)
$NODE_CDMD_{n,r}$ = net node demands remaining constant each NEMS iteration in region r, for network n (Bcf)
$YEAR_CDMD_{n,r}$ = net node demands remaining constant within a forecast year in region r, for network n (Bcf)
$PFUEL_{n,r}$ = Pipeline fuel consumption in region r, for network n (Bcf)
$FLOW_{n,a}$ = Seasonal flow on network n, along arc a [out of region r] (Bcf)
$ZNGQTY_F_{nonu,r}$ = Core demands in region r, by nonelectric sectors nonu (Bcf)
$ZNGQTY_I_{nonu,r}$ = Noncore demands in region r, by nonelectric sectors nonu(Bcf)
$ZNGUQTY_F_{jutil}$ = Core utility demands in NGTDM/EMM subregion jutil [subset of region r] (Bcf)
$ZNGUQTY_I_{jutil}$ = Noncore utility demands in NGTDM/EMM subregion jutil [subset of region r] (Bcf)
$ZADGPRD_s$ = Onshore and offshore associated-dissolved gas production in supply subregion s (Bcf)
$DISCR_{n,r,t}$ = Lower 48 discrepancy in region r, for network n, in forecast year t (Bcf)[58]

[58]Projected lower 48 discrepancies are primarily based on the average historical level from 1990 to 2009. Discrepancies are adjusted in the STEO years to account for STEO discrepancy (Appendix E, STDISCR) and annual net storage withdrawal

$CN_DISCR_{n,cn}$	=	Canada discrepancy in Canadian region cn, for network n (Bcf)
$CN_DMD_{cn,t}$	=	Canada demand in Canadian region cn, in forecast year t (Bcf, Appendix E)
$SAFLOW_{a,t}$	=	Secondary flows out of region r, along arc a [includes Canadian and Mexican exports, Canadian gas that flows through the U.S., and lower 48 bidirectional flows] (Bcf)
$SAFLOW_{a',t}$	=	Secondary flows into region r, along arc a' [includes Mexican imports, Canadian imports into the East North Central Census Division, Canadian gas that flows through the U.S., and lower 48 bidirectional flows] (Bcf)
QAK_ALB_t	=	Natural gas flow from Alaska into Alberta via pipeline (Bcf)
$ZTOTSUP_r$	=	Total supply from SNG liquids, SNG coal, and other supplemental in forecast year t (Bcf)
$OGQNGIMP_{L,t}$	=	LNG imports from LNG region L, in forecast year t (Bcf)
$CN_FIXSUP_{cn,t}$	=	Fixed supply from Canadian region cn, in forecast year t (Bcf, Appendix E)
PK1, PK2	=	Fraction of either in-flow or out-flow volumes corresponding to peak season (composed of PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, or PKSHR_YR)
$PKSHR_DMD_{nonu,r}$	=	Average (2001-2009) fraction of annual consumption in each nonelectric sector in region r corresponding to the peak season
$PKSHR_UDMD_{jutil}$	=	Average (1994-2009, except New England 1997-2009) fraction of annual consumption in the electric generator sector in region r corresponding to the peak season
$PKSHR_PROD_s$	=	Average (1994-2009) fraction of annual production in supply region s corresponding to the peak season (fraction, Appendix E)
PKSHR_CDMD	=	Fraction of annual Canadian demand corresponding to the peak season (fraction, Appendix E)
PKSHR_YR	=	Fraction of the year represented by the peak season
PKSHR_SUPLM	=	Average (1990-2009) fraction of supplemental supply corresponding to the peak season
PKSHR_ILNG	=	Fraction of LNG imports corresponding to the peak season
PKSHR_ECAN	=	Fraction of Canadian exports transferred in peak season
PKSHR_ICAN	=	Fraction of Canadian imports transferred in peak season
PKSHR_EMEX	=	Fraction of Mexican exports transferred in peak season
PKSHR_IMEX	=	Fraction of Mexican imports transferred in peak season
r	=	region/node
n	=	network (peak or off-peak)
PK,OP	=	Peak and off-peak network, respectively
nonu	=	Nonelectric sector ID: residential, commercial, industrial, transportation
jutil	=	Utility sector subregion ID in region r
a,a'	=	Arc ID for arc entering (a') or exiting (a) region r

(Appendix E, NNETWITH) forecasts, and differences between NEMS and STEO total consumption levels Appendix E, STENDCON). These adjustments are phased out over a user-specified number of years (Appendix E, STPHAS_YR).

s = Supply subregion ID into region r (1-21)
cn = Canadian supply subregion ID in region r (1-2)
L = LNG import region ID into region r (1-12)
st = Arc ID corresponding to storage supply into region r
t = Current forecast year

Pipeline Fuel Use and Intraregional Flows

Pipeline fuel consumption represents the natural gas consumed by compressors to transmit gas along pipelines within a region. In the ITS, pipeline fuel consumption is modeled as a regional demand component. It is estimated for each region on each network using a historically based factor, corresponding net demands, and a multiplicative scaling factor. The scaling factor is used to calibrate the results to equal the most recent national *Short-Term Energy Outlook (STEO)* forecast[59] for pipeline fuel consumption (Appendix E, STQGPTR), net of pipeline fuel consumption in Alaska (QALK_PIP), and is phased out by a user-specified year (Appendix E, STPHAS_YR). The following equation applies:

$$PFUEL_{n,r} = PFUEL_FAC_{n,r} * NODE_DMD_{n,r} * SCALE_PF \quad (61)$$

where,

$PFUEL_{n,r}$ = Pipeline fuel consumption in region r, for network n (Bcf)
$PFUEL_FAC_{n,r}$ = Average (2004-2009) historical pipeline fuel factor in region r, for network n (calculated historically for each region as equal PFUEL/NODE_DMD)
$NODE_DMD_{n,r}$ = Net demands (excluding pipeline fuel) in region r, for network n (Bcf)
SCALE_PF = STEO benchmark factor for pipeline fuel consumption
n = network (peak and off-peak)
r = region/node

After pipeline fuel consumption is calculated for each node on the network, the regional/seasonal value is added to net demand at the respective node. Flows into a node ($FLOW_{n,a}$) are then defined using net demands and a sharing algorithm (described below). The regional pipeline fuel quantity (net of intraregional pipeline fuel consumption) [60] is distributed over the pipeline arcs entering the region. This is accomplished by sharing the net pipeline fuel quantity over all of the interregional pipeline arcs entering the region, based on their relative levels of natural gas flow:

[59]EIA produces a separate quarterly forecast for primary national energy statistics over the next several years. For certain forecast items, the NEMS is calibrated to produce an equivalent (within 2 to 5 percent) result for these years. For *AEO2011*, the years calibrated to *STEO* results were 2010 and 2011.

[60]Currently, intraregional pipeline fuel consumption (INTRA_PFUEL) is set equal to the regional pipeline fuel consumption level (PFUEL); therefore, pipeline fuel consumption along an arc (ARC_PFUEL) is set to zero. The original design was to allocate pipeline fuel according to flow levels on arcs and within a region. It was later determined that assigning all of the pipeline fuel to a region would simplify benchmarking the results to the STEO and would not change the later calculation of the price impacts of pipeline fuel use.

$$ARC_PFUEL_{n,a} = (PFUEL_{n,r} - INTRA_PFUEL_{n,r}) * \frac{FLOW_{n,a}}{TFLOW} \quad (62)$$

where,

$ARC_PFUEL_{n,a}$ = Pipeline fuel consumption along arc a (into region r), for network n (Bcf)
$PFUEL_{n,r}$ = Pipeline fuel consumption in region r, for network n (Bcf)
$INTRA_PFUEL_{n,r}$ = Intraregional pipeline fuel consumption in region r, for network n (Bcf)
$FLOW_{n,a}$ = Interregional pipeline flow along arc a (into region r), for network n (Bcf)
TFLOW = Total interregional pipeline flow [into region r] (Bcf)
n = network (peak and off-peak)
r = region/node
a = arc

Pipeline fuel consumption along an interregional arc and within a region on an intrastate pipeline will have an impact on pipeline tariffs and node prices. This will be discussed later in the Arc, Node, and Storage Prices subsection.

The flows of natural gas on the interstate pipeline system within each NGTDM region (as opposed to between two NGTDM regions) are established for the purpose of setting the associated revenue requirements and tariffs. The charge for moving gas within a region (INTRAREG_TAR), but on the interstate pipeline system, is taken into account when setting city gate prices, described below. The algorithm for setting intraregional flows is similar to the method used for setting pipeline fuel consumption. For each region in the historical years, a factor is calculated reflective of the relationship between the net node demand and the intraregional flow. This factor is applied to the net node demand in each forecast year to approximate the associated intraregional flow. Pipeline fuel consumption is excluded from the net node demand for this calculation, as follows:

Calculation of intraregional flow factor based on data for an historical year:

$$FLO_FAC_{n,r} = INTRA_FLO_{n,r} \; / \; (NODE_DMD_{n,r} - PFUEL_{n,r}) \quad (63)$$

Forecast of intraregional flow:

$$INTRA_FLO_{n,r} = FLO_FAC_{n,r} * (NODE_DMD_{n,r} - PFUEL_{n,r}) \quad (64)$$

where,

$INTRA_FLO_{n,a}$ = Intraregional, interstate pipeline flow within region r, for network n (Bcf)
$PFUEL_{n,r}$ = Pipeline fuel consumption in region r, for network n (Bcf)
$NODE_DMD_{n,r}$ = Net demands (with pipeline fuel) in region r, for network n (Bcf)

$FLO_FAC_{n,r}$ = Average (1990 - 2009) historical relationship between net node demand and intraregional flow
n = network (peak and off-peak)
r = region/node

Historical annual intraregional flows are set for the peak and off-peak periods based on the peak and off-peak share of net node demand in each region.

Sharing Algorithm, Flows, and Capacity Expansion

Moving systematically downward from node to node through the acyclic network, the sharing algorithm is allocates net demands ($NODE_DMD_{n,r}$) across all arcs feeding into the node. These "inflow" arcs carry flows from local supply sources, storage (net withdrawals during peak period only), or other regions (interregional arcs). If any of the resulting flows exceed their corresponding maximum levels,[61] then the excess flows are reallocated to the unconstrained arcs, and new shares are calculated accordingly. At each node within a network, the sharing algorithm determines the percent of net demand ($SHR_{n,a,t}$) that is satisfied by each of the arcs entering the region.

The sharing algorithm (shown below) dictates that the share ($SHR_{n,a,t}$) of demand for one arc into a node is a function of the share defined in the previous model year[62] and the ratio of the price on the one arc relative to the average of the prices on all of the arcs into the node, as defined the previous cycle up the network tree. These prices ($ARC_SHRPR_{n,a}$) represents the unit cost associated with an arc going into a node, and is defined as the sum of the unit cost at the source node ($NODE_SHRPR_{n,r}$) *and* the tariff charge along the arc ($ARC_SHRFEE_{n,a}$). (A description of how these components are developed is presented later.) The variable γ is an assumed parameter that is always positive. This parameter can be used to prevent (or control) broad shifts in flow patterns from one forecast year to the next. Larger values of γ increase the sensitivity of $SHR_{n,a,t}$ to relative prices; a very large value of γ would result in behavior equivalent to cost minimization. The algorithm is presented below:

$$SHR_{n,a,t} = \frac{ARC_SHRPR_{n,a}^{-\gamma}}{\frac{\sum_{b} ARC_SHRPR_{n,b}^{-\gamma}}{N}} * SHR_{n,a,t-1} \quad (65)$$

where,
$SHR_{n,a,t}$, $SHR_{n,a,t-1}$ = The fraction of demand represented along inflow arc a on network n, in year t (or year t-1) [Note: The value for year t-1 has a lower limit set to 0.01]

[61] Maximum flows include potential pipeline or storage capacity additions, and maximum production levels.

[62] When planned pipeline capacity is added at the beginning of a forecast year, the value of SHR_{t-1} is adjusted to reflect a percent usage (PCTADJSHR, Appendix E) of the new capacity. This adjustment is based on the assumption that last year's share would have been higher if not constrained by the existing capacity levels.

$ARC_SHRPR_{n,a\ or\ b}$ = The last price calculated for natural gas from inflow arc a (or b) on network n [i.e., from the previous cycle while moving up the network] (87$/Mcf)
N = Total number of arcs into a node
γ = Coefficient defining degree of influence of relative prices (represented as GAMMAFAC, Appendix E)
t = forecast year
n = network (peak or off-peak)
a = arc into a region
r = region/node
b = set of arcs into a region

[Note: The resulting shares ($SHR_{n,a,t}$) along arcs going into a node are then normalized to ensure that they add to one.]

Seasonal flows are generated for each arc using the resulting shares and net node demands, as follows:

$$FLOW_{n,a} = SHR_{n,a,t} * NODE_DMD_{n,r} \quad (66)$$

where,

$FLOW_{n,a}$ = Interregional flow (into region r) along arc a, for network n (Bcf)
$SHR_{n,a,t}$ = The fraction of demand represented along inflow arc a on network n, in year t
$NODE_DMD_{n,r}$ = Net node demands in region r, for network n (Bcf)
n = network (peak or off-peak)
a = arc into a region
r = region/node

These flows must not exceed the maximum flow limits ($MAXFLO_{n,a}$) defined for each arc on each network. The algorithm used to define maximum flows may differ depending on the type of arc (storage, pipeline, supply, Canadian imports) and the network being referenced. For example, maximum flows for all *peak* network arcs are a function of the maximum permissible annual capacity levels ($MAXPCAP_{PK,a}$) and peak utilization factors. However, maximum *pipeline* flows along the *off-peak* network arcs are a function of the annual capacity defined by peak flows and off-peak utilization factors. Thus, maximum flows along the off-peak network depend on whether or not capacity was added during the peak period. Also, maximum flows from *supply* sources in the off-peak network are limited by maximum annual capacity levels and off-peak utilization. (Note: *storage* arcs do not enter nodes on the off-peak network; therefore, maximum flows are not defined there.) The following equations define maximum flow limits and maximum annual capacity limits:

Maximum peak flows (note: for storage arcs, PKSHR_YR=1):

$$MAXFLO_{PK,a} = MAXPCAP_{PK,a} * (PKSHR_YR * PKUTZ_a) \quad (67)$$

with $MAXPCAP_{PK}$,a defined by type as follows:

for *Supply*[63]:

$$MAXPCAP_{PK,a} = ZOGRESNG_s * ZOGPRRNG_s * MAXPRRFAC * (1 - (PCTLP_r * SCALE_LP_t)) \quad (68)$$

for *Pipeline*:

$$MAXPCAP_{PK,a} = PTMAXPCAP_{i,j} \quad (69)$$

for *Storage*:

$$MAXPCAP_{PK,a} = PTMAXPSTR_{st} \quad (70)$$

for *Canadian imports*:

$$MAXPCAP_{PK,a} = CURPCAP_{a,t} \quad (71)$$

Maximum off-peak pipeline flows:

$$MAXFLO_{OP,a} = MAXPCAP_{OP,a} * ((1 - PKSHR_YR) * OPUTZ_a) \quad (72)$$

with MAXPCAPOP,a is defined as follows for

either *current capacity:*

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} \quad (73)$$

or *current capacity* plus *capacity additions*,

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} + ((1 + XBLD) * (\frac{FLOW_{PK,a}}{PKSHR_YR * PKUTZ_a} - CURPCAP_{a,t})) \quad (74)$$

or, for *pipeline arc entering region 10 (Florida), peak maximum capacity*,

$$MAXPCAP_{OP,a} = MAXPCAP_{PK,a} \quad (75)$$

[63]In historical years, historical production values are used in place of the product of ZOGRESNG and ZOGPRRNG.

Maximum off-peak flows from supply sources:

$$MAXFLO_{OP,a} = MAXPCAP_{PK,a} * ((1 - PKSHR_YR) * OPUTZ_a) \quad (76)$$

where,

$MAXFLO_{n,a}$ = Maximum flow on arc a, in network n [PK-peak or OP-off-peak] (Bcf)
$MAXPCAP_{n,a}$ = Maximum annual physical capacity along arc a for network n (Bcf)
$CURPCAP_{a,t}$ = Current annual physical capacity along arc a in year t (Bcf)
$ZOGRESNG_s$ = Natural gas reserve levels for supply source s [defined by OGSM] (Bcf)
$ZOGPRRNG_s$ = Expected natural gas production-to-reserves ratio for supply source s [defined by OGSM] (fraction)
MAXPRRFAC = Factor to set maximum production-to-reserves ratio [MAXPRRCAN for Canada] (Appendix E)
$PCTLP_t$ = Average (1996-2009) fraction of production consumed as lease and plant fuel in forecast year t
$SCALE_LP_t$ = Scale factor for STEO year percent lease and plant consumption for forecast year t to force regional lease and plant consumption forecast to total to STEO forecast.
$PTMAXPCAP_{i,j}$ = Maximum pipeline capacity along arc defined by source node i and destination node j [defined by PTS] (Bcf)
$PTMAXPSTR_{st}$ = Maximum storage capacity for storage source st [defined by PTS] (Bcf)
$FLOW_{PK,a}$ = Flow along arc a for the peak network (Bcf)
PKSHR_YR = Fraction of the year represented by peak season
$PKUTZ_a$ = Pipeline utilization along arc a for the peak season (fraction, Appendix E)
$OPUTZ_a$ = Pipeline utilization along arc a for the off-peak season (fraction, Appendix E)
XBLD = Percent increase over capacity builds to account for weather (fraction, Appendix E)
a = arc
t = forecast year
n = network (peak or off-peak)
PK, OP = peak and off-peak network, respectively
s,st = supply or storage source
i,j = regional source (i) and destination (j) link on arc a

If the model has been restricted from building capacity through a specified forecast year (Appendix E, NOBLDYR), then the maximum pipeline and storage flow for either network will be based only on current capacity and utilization for that year.

If the flows defined by the sharing algorithm above exceed these maximum levels, then the excess flow is reallocated along adjacent arcs that have excess capacity. This is achieved by

determining the flow distribution of the qualifying adjacent arcs, and distributing the excess flow according to this distribution. These adjacent arcs are checked again for excess flow; if excess flow is found, the reallocation process is performed again on all arcs with space remaining. This applies to supply and pipeline arcs on all networks, as well as storage withdrawal arcs on the peak network. To handle the event where insufficient space or supply is available on all inflowing arcs to meet demand, a backstop supply ($BKSTOP_{n,r}$) is available at an incremental price ($RBKSTOP_PADJ_{n,r}$). The intent is to dissuade use of the particular route, or to potentially lower demands. Backstop pricing will be defined in another section below.

With the exception of import and export arcs,[64] the resulting interregional flows defined by the sharing algorithm for the peak network are used to determine if *pipeline* capacity expansion should occur. Similarly, the resulting storage withdrawal quantities in the peak season define the *storage* capacity expansion levels. Thus, initially capacity expansion is represented by the difference between new capacity levels ($ACTPCAP_a$) and current capacity ($CURPCAP_{a,t}$, previous model year capacity plus planned additions). In the module, these initial new capacity levels are defined as follows:

Storage:

$$ACTPCAP_a = \frac{FLOW_{PK,a}}{PKUTZ_a} \tag{77}$$

Pipeline:

$$ACTPCAP_a = MAXPCAP_{OP,a} \tag{78}$$

Pipeline arc entering region 10 (Florida):

$$ACTPCAP_a = \text{MAX between} \quad \frac{FLOW_{PK,a}}{PKSHR_YR * PKUTZ_a} \quad \text{and} \quad \frac{FLOW_{OP,a}}{(1 - PKSHR_YR) * OPUTZ_a} \tag{79}$$

where,

$ACTPCAP_a$ = Annual physical capacity along an arc a (Bcf)
$MAXPCAP_{OP,a}$ = Maximum annual physical capacity along pipeline arc a for network n [see equation above] (Bcf)
$FLOW_{n,a}$ = Flow along arc a on network n (Bcf)
$PKUTZ_a$ = Maximum peak utilization of capacity along arc a (fraction, Appendix E)
$OPUTZ_a$ = Maximum off-peak utilization of capacity along arc a (fraction, Appendix E)
$PKSHR_YR$ = Fraction of the year represented by the peak season
a = pipeline and storage arc
n = network (peak or off-peak)

[64]For *AEO2011* capacity expansion on Canadian import arcs were set exogenously (PLANPCAP, Appendix E).

PK = peak season
OP = off-peak season

A second check and potential adjustment are made to these capacity levels to insure that capacity is sufficient to handle estimated flow in the peak month of each period.[65] Since capacity is defined as sustained capacity, it is assumed that the peak month flows should be in accordance with the maximum capacity requirements of the system, short of line packing, propane injections, and planning for the potential of above average temperature months.[66] Peak month consumption and supply levels are set at an assumed fraction of the corresponding period levels. Based on historical relationships, an initial guess is made at the fraction of each period's net storage withdrawals removed during the peak month. With this information, peak month flows are set at the same time flows are set for each period, while coming down the network tree, and following a similar process. At each node a net monthly demand is set equal to the sum of the monthly flows going out of the node, plus the monthly consumption at the node, minus the monthly supply and net storage withdrawals. The period shares are then used to set initial monthly flows, as follows:

$$MTHFLW_{n,a} = MTH_NETNOD_{n,r} * \frac{SHR_{n,a,t}}{\sum_{c} SHR_{n,c,t}} \quad (80)$$

where,

$MTHFLW_{n,a}$ = Monthly flow along pipeline arc a (Bcf)
$MTH_NETNOD_{n,r}$ = Monthly net demand at node r (Bcf)
$SHR_{n,a,t}$ = Fraction of demand represented along inflow arc a
c = set of arcs into a region representing pipeline arcs
n = network (peak or off-peak)
a = arc into a region
r = region/node
t = forecast year

These monthly flows are then compared against a monthly capacity estimate for each pipeline arc and reallocated to the other available arcs if capacity is exceeded, using a method similar to what is done when flows for a period exceed maximum capacity. These adjusted monthly flows are used later in defining the net node demand for nodes lower in the network tree. Monthly capacity is estimated by starting with the previously set ACTPCAP for the pipeline arc divided by the number of months in the year, to arrive at an initial monthly capacity estimate (MTH_CAP). This number is increased if the total of the monthly capacity entering a node exceeds the monthly net node demand, as follows:

$$MTH_CAPADD_{n,a} = MTH_TCAPADD_{n} * \frac{INIT_CAPADD_{n,a}}{\sum_{c} INIT_CAPADD_{n,c}} \quad (81)$$

[65]Currently this is only done in the model for the peak period of the year.

[66]To represent that the pipeline system is built to accommodate consumption levels outside the normal range due to colder than normal temperatures, the net monthly demand levels are increased by an assumed percentage (XBLD, Appendix E).

where,

$MTH_CAPADD_{n,a}$ = Additional added monthly capacity to accommodate monthly flow estimates (Bcf)

$MTH_TCAPADD_{n}$ = Total initial monthly capacity entering a node minus monthly net node demand (Bcf), if value is negative then it is set to zero

$INIT_CAPADD_{n,a}$ = MTHFLWa - MTH_CAPa, if value is negative then it is set to zero (Bcf)

n = network (peak or off-peak)

a = arc into a region

c = set of arcs into a region representing pipeline arcs

The additional added monthly capacity is multiplied by the number of months in the year and added to the originally estimated pipeline capacity levels for each arc (ACTPCAP). Finally, if the net node demand is not close to zero at the lowest node on the network tree (node number 24 in western Canada), then monthly storage levels are adjusted proportionally throughout the network to balance the system for the next time quantities are brought down the network tree.

Wellhead and Henry Hub Prices

Ultimately, all of the network-specific consumption levels are transferred down the network trees and into supply nodes, where corresponding supply prices are calculated. The Oil and Gas Supply Module (OGSM) provides only annual price/quantity supply curve parameters for each supply subregion. Because this alone will not provide a wellhead price differential between seasons, a special methodology has been developed to approximate seasonal prices that are consistent with the annual supply curve. First, in effect the quantity axis of the annual supply curve is scaled to correspond to seasonal volumes (based on the period's share of the year); and the resulting curves are used to approximate seasonal prices. (Operationally within the model this is done by converting seasonal production values to annual equivalents and applying these volumes to the annual supply curve to arrive at seasonal prices.) Finally, the resulting seasonal prices are scaled to ensure that the quantity-weighted average annual wellhead price equals the price obtained from the annual supply curve when evaluated using total annual production. To obtain seasonal wellhead prices, the following methodology is used. Taking one supply region at a time, the model estimates equivalent annual production levels (ANNSUP) for each season.

Peak:

$$ANNSUP = \frac{NODE_QSUP_{PK,s}}{PKSHR_YR} \quad (82)$$

Off-peak:

$$ANNSUP = \frac{NODE_QSUP_{OP,s}}{(1 - PKSHR_YR)} \quad (83)$$

where,

ANNSUP = Equivalent annual production level (Bcf)

$NODE_QSUP_{n,s}$ = Seasonal (n=PK-peak or OP-off-peak) production level for supply region s (Bcf)

PKSHR_YR = Fraction of year represented by peak season
PK = peak season
OP = off-peak season
s = supply region

Next, estimated seasonal prices ($SPSUP_n$) are obtained using these equivalent annual production levels and the annual supply curve function. These initial seasonal prices are then averaged, using quantity weights, to generate an equivalent *average* annual supply price ($SPAVG_s$). An *actual* annual price ($PSUP_s$) is also generated, by evaluating the price on the annual supply function for a quantity equal to the sum of the seasonal production levels. The *average* annual supply price is then compared to the *actual* price. The corresponding ratio (FSF) is used to adjust the estimated seasonal prices to generate final seasonal supply prices ($NODE_PSUP_{n,s}$) for a region.

For a *supply source* s,

$$FSF = \frac{PSUP_s}{SPAVG_s} \tag{84}$$

and,

$$NODE_PSUP_{n,s} = SPSUP_n * FSF \tag{85}$$

where,

FSF = Scaling factor for seasonal prices
$PSUP_s$ = Annual supply price from the annual supply curve for supply region s (87$/Mcf)
$SPAVG_s$ = Quantity-weighted average annual supply price using peak and off-peak prices and production levels for supply region s (87$/Mcf)
$NODE_PSUP_{n,s}$ = Adjusted seasonal supply prices for supply region s (87$/Mcf)
$SPSUP_n$ = Estimated seasonal supply prices [for supply region s] (87$/Mcf)
n = network (peak or off-peak)
s = supply source

During the STEO years (2010 and 2011 for *AEO2011*), national average wellhead prices (lower 48 only) generated by the model are compared to the national STEO wellhead price forecast to generate a benchmark factor ($SCALE_WPR_t$). This factor is used to adjust the regional (annual and seasonal) lower 48 wellhead prices to equal STEO results. This benchmark factor is only applied for the STEO years. The benchmark factor is applied as follows:

Annual:

$$PSUP_s = PSUP_s * SCALE_WPR_t \tag{86}$$

Seasonal:

$$NODE_PSUP_{n,s} = NODE_PSUP_{n,s} * SCALE_WPR_t \tag{87}$$

where,

$PSUP_s$ = Annual supply price from the annual supply curve for supply region s (87$/Mcf)
$NODE_PSUP_{n,s}$ = Adjusted seasonal supply prices for supply region s (87$/Mcf)
$SCALE_WPR_t$ = STEO benchmark factor for wellhead price in year t
n = network (peak or off-peak)
s = supply source
t = forecast year

A similar adjustment is made for the Canadian supply price, with an additional multiplicative factor applied (STSCAL_CAN, Appendix E) which is set to align Canadian import levels with STEO results.

While the NGTDM does not explicitly represent the Henry Hub within its modeling structure, the module reports a projected value for reporting purposes. The price at the Henry Hub is set using an econometrically estimated equation as a function of the lower 48 average natural gas wellhead price, as follows:

$$oOGHHPRNG_t = 1.00439 * e^{0.090246} * oOGWPRNG_{s=13,t}^{1.00119} \quad (88)$$

where,
$oOGHHPRNG_t$ = Natural gas price at the Henry Hub (87$/MMBtu)
$oOGWPRNG_{s,t}$ = Average natural gas wellhead price for supply region 13, representing the lower 48 average (87$/Mcf)
s = supply source/region
t = forecast year

Details about the generation of this estimated equation and associated parameters are provided in **Table F9**, Appendix F.

Arc Fees (Tariffs)

Fees (or tariffs) along arcs are used in conjunction with supply, storage, and node prices to determine competing arc prices that, in turn, are used to determine network flows, transshipment node prices, and delivered prices. Arc fees exist in the form of pipeline tariffs, storage fees, and gathering charges. Pipeline tariffs are transportation rates along interregional arcs, and reflect the average rate charged over all of the pipelines represented along an arc. Storage fees represent the charges applied for storing, injecting, and withdrawing natural gas that is injected in the off-peak period for use in the peak period, and are applied along arcs connecting the storage sites to the peak network. Gathering charges are applied to the arcs going from the supply points to the transshipment nodes.

Pipeline and storage tariffs consist of both a fixed (volume independent) term and a variable (volume dependent) term. For pipelines the fixed term ($ARC_FIXTAR_{n,a,t}$) is set in the PTS at the beginning of each forecast year to represent pipeline usage fees and does not vary in response to changes in flow in the current year. For storage, the fixed term establishes a minimum and is set to $0.001 per Mcf. The variable term is obtained from tariff/capacity curves

provided by two PTS functions and represents reservation fees for pipelines and all charges for storage. These two functions are NGPIPE_VARTAR and X1NGSTR_VARTAR. When determining network flows a different set of tariffs ($ARC_SHRFEE_{n,a}$) are used than are used when setting delivered prices ($ARC_ENDFEE_{n,a}$).

In the peak period ARC_SHRFEE equals ARC_ENDFEE and the total tariff (reservation plus usage fee). In the off-peak period, ARC_ENDFEE represents the total tariff as well, but ARC_SHRFEE represents the fee that drives the flow decision. In previous AEOs this was set to just the usage fee. The assumption behind this structure was that delivered prices will ultimately reflect reservation charges, but that during the off-peak period in particular, decisions regarding the purchase and transport of gas are made largely independently of where pipeline is reserved and the associated fees. For *AEO2011* the ARC_SHRFEE was set similarly to ARC_ENDFEE because the usage fees seemed to be underestimating off-peak market prices. (This decision will be reexamined in the future.) During the peak period, the gas is more likely to flow along routes where pipeline is reserved; therefore the flow decision is more greatly influenced by the relative reservation fees.[67] The following arc tariff equations apply:

Pipeline:

$$\begin{aligned} ARC_ENDFEE_{n,a} &= ARC_FIXTAR_{n,a,t} + NGPIPE_VARTAR(n,a,i,j,FLOW_{n,a}) \\ ARC_SHRFEE_{n,a} &= ARC_FIXTAR_{n,a,t} + NGPIPE_VARTAR(n,a,i,j,FLOW_{n,a}) \end{aligned} \quad (89)$$

Storage:

$$\begin{aligned} ARC_SHRFEE_{n,a} &= ARC_FIXTAR_{n,a,t} + X1NGSTR_VARTAR(st,FLOW_{n,a}) \\ ARC_ENDFEE_{n,a} &= ARC_FIXTAR_{n,a,t} + X1NGSTR_VARTAR(st,FLOW_{n,a}) \end{aligned} \quad (90)$$

where,

$ARC_SHRFEE_{n,a}$ = Total arc fees along arc a for network n [used with sharing algorithm] (87$/Mcf)

$ARC_ENDFEE_{n,a}$ = Total arc fees along arc a for network n [used with delivered pricing] (87$/Mcf)

$ARC_FIXTAR_{n,a,t}$ = Fixed (or usage) fees along an arc a for a network n in time t (87$/Mcf)

NGPIPE_VARTAR = PTS function to define pipeline tariffs representing reservation fees for specified arc at given flow level

X1NGSTR_VARTAR = PTS function to define storage fees at specified storage region for given storage level

[67]Reservation fees are frequently considered "sunk" costs and are not expected to influence short-term purchasing decisions as much, but still must ultimately be paid by the end-user. Therefore within the ITS, the arc prices used in determining flows can have tariff components defined differently than their counterparts (arc and node prices) ultimately used to establish delivered prices.

$FLOW_{n,a}$ = Flow of natural gas on the arc in the given period
n = network (peak or off-peak)
a = arc
i, j = from transshipment node i to transshipment node j

A methodology for defining gathering charges has not been developed but may be developed in a separate effort at a later date.[68] In order to accommodate this, the supply arc indices in the variable $ARC_FIXTAR_{n,a}$ have been reserved for this information (currently set to 0). Since the historical wellhead price represents a first-purchase price, the cost of gathering is frequently already included and no further charge should be added.

Arc, Node, and Storage Prices

Prices at the transshipment nodes (or node prices) represent intermediate prices that are used to determine regional delivered prices. Node prices (along with tariffs) are also used to help make model decisions, primarily within the flow-sharing algorithm. In both cases it is not required (as described above) to set delivered or arc prices using the same price components or methods used to define prices needed to establish flows along the networks (e.g., in setting $ARC_SHRPR_{n,a}$ in the share equation). Thus, *process-specific* node prices ($NODE_ENDPR_{n,r}$ and $NODE_SHRPR_{n,r}$) are generated using *process-specific* arc prices ($ARC_ENDPR_{n,a}$ and $ARC_SHRPR_{n,a}$) which, in turn, are generated using *process-specific* arc fees/tariffs ($ARC_ENDFEE_{n,a}$ and $ARC_SHRFEE_{n,a}$).

The following equations define the methodology used to calculate arc prices. Arc prices are first defined as the average node price at the source node plus the arc fee (pipeline tariff, storage fee, or gathering charge). Next, the arc prices along pipeline arcs are adjusted to account for the cost of pipeline fuel consumption. These equations are as follows:

$$ARC_SHRPR_{n,a} = NODE_SHRPR_{n,rs} + ARC_SHRFEE_{n,a}$$

$$ARC_ENDPR_{n,a} = NODE_ENDPR_{n,rs} + ARC_ENDFEE_{n,a} \quad (91)$$

with the adjustment accomplished through the assignment statements:

$$ARC_SHRPR_{n,a} = \frac{(ARC_SHRPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC_PFUEL_{n,a})}$$

$$ARC_ENDPR_{n,a} = \frac{(ARC_ENDPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC_PFUEL_{n,a})} \quad (92)$$

[68] In a previous version of the NGTDM, "gathering" charges were used to benchmark the regional wellhead prices to historical values. It is possible that they may be used (at least in part) to fulfill the same purpose in the ITS. In the past an effort was made, with little success, to derive representative gathering charges. Currently, the gathering charge portion of the tariff along the supply arcs is assumed to be zero.

where,

$ARC_SHRPR_{n,a}$ = Price calculated for natural gas along inflow arc a for network n [used with sharing algorithm] (87$/Mcf)

$ARC_ENDPR_{n,a}$ = Price calculated for natural gas along inflow arc a for network n [used with delivered pricing] (87$/Mcf)

$NODE_SHRPR_{n,r}$ = Node price for region i on network n [used with sharing algorithm] (87$/Mcf)

$NODE_ENDPR_{n,r}$ = Node price for region i on network n [used with delivered pricing] (87$/Mcf

$ARC_SHRFEE_{n,a}$ = Tariff along inflow arc a for network n [used with sharing algorithm] (87$/Mcf)

$ARC_ENDFEE_{n,a}$ = Tariff along inflow arc a for network n [used with delivered pricing] (87$/Mcf)

$ARC_PFUEL_{n,a}$ = Pipeline fuel consumption along arc a, for network n (Bcf)

$FLOW_{n,a}$ = Network n flow along arc a (Bcf)

n = network (peak or off-peak)

a = arc

rs = region corresponding to source link on arc a

Although each type of node price may be calculated differently (e.g., average prices for delivered price calculation, marginal prices for flow sharing calculation, or some combination of these for each), the current model uses the quantity-weighted averaging approach to establish node prices for both the delivered pricing and flow sharing algorithm pricing. Prices from all arcs entering a node are included in the average. Node prices then are adjusted to account for intraregional pipeline fuel consumption. The following equations apply:

$$NODE_SHRPR_{n,rd} = \frac{\Sigma_a (ARC_SHRPR_{n,a} * FLOW_{n,a})}{\Sigma_a (FLOW_{n,a} - ARC_PFUEL_{n,a})}$$

$$NODE_ENDPR_{n,rd} = \frac{\Sigma_a (ARC_ENDPR_{n,a} * FLOW_{n,a})}{\Sigma_a (FLOW_{n,a} - ARC_PFUEL_{n,a})} \quad (93)$$

and,

$$NODE_SHRPR_{n,rd} = \frac{(NODE_SHRPR_{n,rd} * NODE_DMD_{n,rd})}{(NODE_DMD_{n,rd} - INTRA_PFUEL_{n,rd})}$$

$$NODE_ENDPR_{n,rd} = \frac{(NODE_ENDPR_{n,rd} * NODE_DMD_{n,rd})}{(NODE_DMD_{n,rd} - INTRA_PFUEL_{n,rd})} \quad (94)$$

where,

$NODE_SHRPR_{n,r}$ = Node price for region r on network n [used with flow sharing algorithm] (87$/Mcf)
$NODE_ENDPR_{n,r}$ = Node price for region r on network n [used with delivered pricing] (87$/Mcf)
$ARC_SHRPR_{n,a}$ = Price calculated for natural gas along inflow arc a for network n [used with flow sharing algorithm] (87$/Mcf)
$ARC_ENDPR_{n,a}$ = Price calculated for natural gas along inflow arc a for network n [used with delivered pricing] (87$/Mcf)
$FLOW_{n,a}$ = Network n flow along arc a (Bcf)
$ARC_PFUEL_{n,a}$ = Pipeline fuel consumed along the pipeline arc a, network n (Bcf)
$INTRA_PFUEL_{n,r}$ = Intraregional pipeline fuel consumption in region r, network n (Bcf)
$NODE_DMD_{n,r}$ = Net node demands (w/ pipeline fuel) in region r, network n (Bcf)
n = network (peak or off-peak)
a = arc
rd = region r destination link along arc a

Once node prices are established for the off-peak network, the cost of the gas injected into storage can be modeled. Thus, for every region where storage is available, the storage node price is set equal to the off-peak regional node price. This applies for both the delivered pricing and the flow sharing algorithm pricing:

$$NODE_SHRPR_{PK,i} = NODE_SHRPR_{OP,r}$$
$$NODE_ENDPR_{PK,i} = NODE_ENDPR_{OP,r} \quad (95)$$

where,

$NODE_SHRPR_{PK,i}$ = Price at node i [used with flow sharing algorithm] (87$/Mcf)
$NODE_SHRPR_{OP,r}$ = Price at node r in off-peak network [used with flow sharing algorithm] (87$/Mcf)
$NODE_ENDPR_{PK,ii}$ = Price at node i [used with delivered pricing] (87$/Mcf)
$NODE_ENDPR_{OP,r}$ = Price at node r in off-peak network [used with delivered pricing] (87$/Mcf)
PK, OP = peak and off-peak network, respectively
i = node ID for storage
r = region ID where storage exists

Backstop Price Adjustment

Backstop supply[69] is activated when seasonal net demand within a region exceeds total available supply for that region. When backstop occurs, the corresponding *share* node price ($NODE_SHRPR_{n,r}$) is adjusted upward in an effort to reduce the demand for gas from this

[69]Backstop supply can be thought of as a high-priced alternative supply when no other options are available. Within the model, it also plays an operational role in sending a price signal when equilibrating the network that additional supplies are unavailable along a particular path in the network.

source. If this initial price adjustment ($BKSTOP_PADJ_{n,r}$) is not sufficient to eliminate backstop, on the next cycle down the network tree, an additional adjustment ($RBKSTOP_PADJ_{n,r}$) is added to the original adjustment, creating a cumulative price adjustment. This process continues until the backstop quantity is reduced to zero, or until the maximum number of ITS cycles has been completed. If backstop is eliminated, then the cumulative price adjustment level is maintained, as long as backstop does not resurface, and until ITS convergence is achieved. Maintaining a backstop adjustment is necessary because complete removal of this high-price signal would cause demand for this source to increase again, and backstop would return. However, if the need for backstop supply recurs following a cycle which did not need backstop supply, then the price adjustment ($BKSTOP_PADJ_{n,r}$) factor is reduced by one-half and added to the cumulative adjustment variable, with the process continuing as described above. The objective is to eliminate the need for backstop supply while keeping the associated price at a minimum. The node prices are adjusted as follows:

$$NODE_SHRPR_{n,r} = NODE_SHRPR_{n,r} + RBKSTOP_PADJ_{n,r} \quad (96)$$

$$RBKSTOP_PADJ_{n,r} = RBKSTOP_PADJ_{n,r} + BKSTOP_PADJ_{n,r} \quad (97)$$

where,

$NODE_SHRPR_{n,r}$ = Node price for region r on network n [used with flow sharing algorithm] (87$/Mcf)
$RBKSTOP_PADJ_{n,r}$ = Cumulative price adjustment due to backstop (87$/Mcf)
$BKSTOP_PADJ_{n,r}$ = Incremental backstop price adjustment (87$/Mcf)
n = network (peak or off-peak)
r = region

Currently, this cumulative backstop adjustment ($RBKSTOP_PADJ_{n,r}$) is maintained for each NEMS iteration and set to zero only on the first NEMS iteration of each model year. Also, it is not used to adjust the NODE_ENDPR because it is an adjustment for making flow allocation decisions, not for pricing gas for the end-user.

ITS Convergence

The ITS is considered to have converged when the regional/seasonal wellhead prices are within a defined percentage tolerance (PSUP_DELTA) of the prices set during the last ITS cycle and, for those supply regions with relatively small production levels (QSUP_SMALL), production is within a defined tolerance (QSUP_DELTA) of the production set during the last ITS cycle. If convergence does not occur, then a new wellhead price is determined based on a user-specified weighting of the seasonal production levels determined during the current cycle and during the previous cycle down the network. The the new production levels are defined as follows:

$$NODE_QSUP_{n,s} = (QSUP_WT * NODE_QSUP_{n,s}) + ((1 - QSUP_WT) * NODE_QSUPPREV_{n,s}) \quad (98)$$

where,

$NODE_QSUP_{n,s}$ = Production level at supply source s on network n for current ITS cycle (Bcf)

$NODE_QSUPPREV_{n,s}$ = Production level at supply source s on network n for previous ITS cycle (Bcf)

$QSUP_WT$ = Weighting applied to production level for current ITS cycle (Appendix E)

n = network (peak or off-peak)

s = supply source

Seasonal prices ($NODE_PSUP_{n,s}$) for these quantities are then determined using the same methodology defined above for obtaining wellhead prices.

End-Use Sector Prices

The NGTDM provides regional end-use or delivered prices for the Electricity Market Module (electric generation sector) and the other NEMS demand modules (nonelectric sectors). For the nonelectric sectors (residential, commercial, industrial, and transportation), prices are established at the NGTDM region and then averaged (when necessary) using quantity-weights to obtain prices at the Census Division level. For the electric generation sector, prices are provided on a seasonal basis and are determined for core and noncore services at two different regional levels: the Census Division level and the NGTDM/EMM level (Chapter 2, **Figure 2-3**).

The first step toward generating these delivered prices is to translate regional, seasonal node prices into corresponding city gate prices ($CGPR_{n,r}$). To accomplish this, seasonal intraregional and intrastate tariffs are added to corresponding regional end-use node prices (NODE_ENDPR). This sum is then adjusted using a city gate benchmark factor ($CGBENCH_{n,r}$) which represents the average difference between historical city gate prices and model results for the historical years of the model. These equations are defined below:

$$CGPR_{n,r} = NODE_ENDPR_{n,r} + INTRAREG_TAR_{n,r} + INTRAST_TAR_{r} + CGBENCH_{n,r} \quad (99)$$

such that:

$$CGBENCH_{n,r} = avg(HCG_BENCH_{n,r,HISYR}) = avg(HCGPR_{n,r,HISYR} - CGPR_{n,r}) \quad (100)$$

where,

$CGPR_{n,r}$ = City gate price in region r on network n in each HISYR (87$/Mcf)

$NODE_ENDPR_{n,r}$ = Node price for region r on network n (87$/Mcf)

$INTRAREG_TAR_{n,r}$ = Intraregional tariff for region r on network n (87$/Mcf)

$INTRAST_TAR_{r}$ = Intrastate tariff in region r (87$/Mcf)

$CGBENCH_{n,r}$ = City gate benchmark factor for region r on network n (87$/Mcf)

$HCG_BENCH_{n,r,HISYR}$ = City gate benchmark factors for region r on network n in historical years HISYR (87$/Mcf)

$HCGPR_{n,r,HISYR}$ = Historical city gate price in region r on network n in historical year HISYR (87$/Mcf)
n = network (peak and off-peak)
r = region (lower 48 only)
HISYR = historical year, over which average is taken (2004-2008, excluding the outlier year of 2006)
avg = straight average of indicated value over indicated historical years of the model.

The intraregional tariffs are the sum of a usage fee (INTRAREG_FIXTAR), provided by the Pipeline Tariff Submodule, and a reservation fee that is set using the same function NGPIPE_VARTAR that is used in setting interregional tariffs and was described previously. The benchmark factor represents an adjustment to calibrate city gate prices to historical values.

Seasonal distributor tariffs are then added to the city gate prices to get seasonal, sectoral delivered prices by the NGTDM regions for nonelectric sectors and by the NGTDM/EMM subregions for the electric generation sector. The prices for residential, commercial, and electric generation sectors (core and noncore) are then adjusted using STEO benchmark factors ($SCALE_FPR_{sec,t}$, $SCALE_IPR_{sec,t}$)[70] to calibrate the results to equal the corresponding national STEO delivered prices. Each seasonal sector price is then averaged to get an annual, sectoral delivered price for each representative region. The following equations apply.

Nonelectric Sectors (except core transportation):

$$NGPR_SF_{n,sec,r} = CGPR_{n,r} + DTAR_SF_{n,sec,r} + SCALE_FPR_{sec,t}$$

$$NGPR_SI_{n,sec,r} = CGPR_{n,r} + DTAR_SI_{n,sec,r} + SCALE_IPR_{sec,t} \quad (101)$$

$$NGPR_F_{sec,r} = NGPR_SF_{PK,sec,r} * PKSHR_DMD_{sec,r} + NGPR_SF_{OP,sec,r} * (1. - PKSHR_DMD_{sec,r})$$

$$NGPR_I_{sec,r} = NGPR_SI_{PK,sec,r} * PKSHR_DMD_{sec,r} + NGPR_SI_{OP,sec,r} * (1. - PKSHR_DMD_{sec,r}) \quad (102)$$

where,

$NGPR_SF_{n,sec,r}$ = Seasonal (n) core nonelectric sector (sec) price in region r (87$/Mcf)
$NGPR_SI_{n,sec,r}$ = Seasonal (n) noncore nonelectric sector (sec) price in region r (87$/Mcf)
$NGPR_F_{sec,r}$ = Annual core nonelectric sector (sec) price in region r (87$/Mcf)
$NGPR_I_{sec,r}$ = Annual noncore nonelectric sector (sec) price in region r (87$/Mcf)

[70]The STEO scale factors are linearly phased out over a user-specified number of years (Appendix E, STPHAS_YR) after the last STEO year. STEO benchmarking is not done for the industrial price, because of differences in the definition of the price in the STEO versus the price in the AEO, nor for the transportation sector since the STEO does not include a comparable value.

$CGPR_{n,r}$ = City gate price in region r on network n (87$/Mcf)
$DTAR_SF_{n.sec,r}$ = Seasonal (n) distributor tariff to core nonelectric sector (sec) in region r (87$/Mcf)
$DTAR_SI_{n.\ sec,r}$ = Seasonal (n) distributor tariff to noncore nonelectric sector (sec) in region r (87$/Mcf)
$PKSHR_DMD_{sec,r}$ = Average (2001-2009) fraction of annual consumption for nonelectric sector in peak season for region r
$SCALE_FPR_{sec,t}$ = STEO benchmark factor for core delivered prices for sector sec, in year t (87$/Mcf)
$SCALE_IPR_{sec,t}$ = STEO benchmark factor for noncore delivered prices for sector sec, in year t (87$/Mcf)
n = network (peak or off-peak)
sec = nonelectric sector
r = region (lower 48 only)

Electric Generation Sector:

$$NGUPR_SF_{n,j} = CGPR_{n,r} + UDTAR_SF_{n,j} + SCALE_FPR_{sec,t}$$

$$NGUPR_SI_{n,j} = CGPR_{n,r} + UDTAR_SI_{n,j} + SCALE_IPR_{sec,t} \quad (103)$$

$$NGUPR_F_j = NGUPR_SF_{PK,j} * PKSHR_UDMD_j + NGUPR_SF_{OP,j} * (1. - PKSHR_UDMD_j)$$

$$NGUPR_I_j = NGUPR_SI_{PK,j} * PKSHR_UDMD_j + NGUPR_SI_{OP,j} * (1. - PKSHR_UDMD_j) \quad (104)$$

where,

$NGUPR_SF_{n,j}$ = Seasonal (n) core utility sector price in region j (87$/Mcf)
$NGUPR_SI_{n,j}$ = Seasonal (n) noncore utility sector price in region j (87$/Mcf)
$NGUPR_F_j$ = Annual core utility sector price in region j (87$/Mcf)
$NGUPR_I_j$ = Annual noncore utility sector price in region j (87$/Mcf)
$CGPR_{n,r}$ = City gate price in region r on network n (87$/Mcf)
$UDTAR_SF_{n,j}$ = Seasonal (n) distributor tariff to core utility sector in region j (87$/Mcf)
$UDTAR_SI_{n,j}$ = Seasonal (n) distributor tariff to noncore utility sector in region j (87$/Mcf)
$PKSHR_UDMD_j$ = Average (1994-2009, except for New England 1997-2009) fraction of annual consumption for the electric generator sector in peak season, for region j
$SCALE_FPR_{sec,t}$ = STEO benchmark factor for core delivered prices for sector sec, in year t (87$/Mcf)
$SCALE_IPR_{sec,t}$ = STEO benchmark factor for noncore delivered prices for sector sec, in year t (87$/Mcf)

n = network (peak PK or off-peak OP)
sec = utility sector (electric generation only)
r = region (lower 48 only)
j = NGTDM/EMM subregion

For *AEO2011*, the natural gas price that was finally sent to the Electricity Market Module for both core and noncore customers was the quantity-weighted average of the core and noncore prices derived from the above equations. This was done to alleviate some difficulties within the Electricity Market Module as selections were being made between different types of natural gas generation equipment.

Core Transportation Sector:

A somewhat different methodology is used to determine natural gas delivered prices for the core (F) transportation sector. The core transportation sector consists of a personal vehicles component and a fleet vehicles component. Like the other nonelectric sectors, seasonal distributor tariffs are added to the regional city gate prices to determine seasonal delivered prices for both components. Annual core prices are then established for each component in a region by averaging the corresponding seasonal prices, as follows:

$$NGPR_TRPV_SF_{n,r} = CGPR_{n,r} + DTAR_TRPV_SF_{n,r} + SCALE_FPR_{sec,t}$$

$$NGPR_TRFV_SF_{n,r} = CGPR_{n,r} + DTAR_TRFV_SF_{n,r} + SCALE_FPR_{sec,t} \quad (105)$$

$$NGPR_TRPV_F_r = NGPR_TRPV_SF_{PK,r} * PKSHR_DMD_{sec,r} + NGPR_TRPV_SF_{OP,r} * (1. - PKSHR_DMD_{sec,r})$$

$$NGPR_TRFV_F_r = NGPR_TRFV_SF_{PK,r} * PKSHR_DMD_{sec,r} + NGPR_TRFV_SF_{OP,r} * (1. - PKSHR_DMD_{sec,r}) \quad (106)$$

where,

$NGPR_TRPV_SF_{n,r}$ = Seasonal (n) price of natural gas used by personal vehicles (core) in region r (87$/Mcf)
$NGPR_TRFV_SF_{n,r}$ = Seasonal (n) price of natural gas used by fleet vehicles (core) in region r (87$/Mcf)
$DTAR_TRPV_SF_{n,r}$ = Seasonal (n) distributor tariff to core transportation (personal vehicles) sector in region r (87$/Mcf)
$DTAR_TRFV_SF_{n,r}$ = Seasonal (n) distributor tariff to core transportation (fleet vehicles) sector in region r (87$/Mcf)
$CGPR_{n,r}$ = City gate price in region r on network n (87$/Mcf)
$NGPR_TRPV_F_r$ = Annual price of natural gas used by personal vehicles (core) in region r (87$/Mcf)
$NGPR_TRFV_F_r$ = Annual price of natural gas used by fleet vehicles (core) in region r (87$/Mcf)

$PKSHR_DMD_{sec,r}$ = Fraction of annual consumption for the transportation sector (sec=4) in the peak season for region r (set to PKSHR_YR)

$SCALE_FPR_{sec,t}$ = STEO benchmark factor for core delivered prices for sector sec, in year t (set to 0 for transportation sector), (87$/Mcf)

n = network (peak PK or off-peak OP)

sec = transportation sector =4

r = region (lower 48 only)

Once the personal vehicles price for natural gas is established, the two core component prices are averaged (using quantity weights) to produce an annual core price for each region ($NGPR_F_{sec=4,r}$). Seasonal core prices are also determined by quantity-weighted averaging of the two seasonal components ($NGPR_SF_{n,sec=4,r}$).

Regional delivered prices can be used within the ITS cycle to approximate a demand response. The submodule can then be resolved with adjusted consumption levels in an effort to speed NEMS convergence. Finally, once the ITS has converged, regional prices are averaged using quantity weights to compute Census Division prices, which are sent to the corresponding NEMS modules.

Import Prices

The price associated with Canadian imports at each of the module's border crossing points is established during the ITS convergence process. Each of these border-crossing points is represented by a node in the network. The import price for a given season and border crossing is therefore equal to the price at the associated node. For reporting purposes, these node prices are averaged using quantity weights to derive an average annual Canadian import price. The prices for imports at the three Mexican border crossings are set to the average wellhead price in the nearest NGTDM region plus a markup (or markdown) that is based on the difference between similar import and wellhead prices historically. The structure for setting LNG import prices is similar to setting Mexican import prices, although regional city gate prices are used instead of wellhead prices. For the facilities for which historical prices are not available (i.e., generic new facilities), an assumption was made about the difference between the regional city gate price and the LNG import price (LNGDIFF, Appendix E).

5. Distributor Tariff Submodule Solution Methodology

This chapter discusses the solution methodology for the Distributor Tariff Submodule (DTS) of the Natural Gas Transmission and Distribution Module (NGTDM). Within each region, the DTS develops seasonal, market-specific distributor tariffs (or city gate to end-use markups) that are applied to projected seasonal city gate prices to derive end-use or delivered prices. Since most industrial and electric generator customers do not purchase their gas through local distribution companies, their "distributor tariff" represents the difference between the average price paid by local distribution companies at the city gate and the average price paid by the industrial or electric generator customer.[71] Distributor tariffs are defined for both core and noncore markets within the industrial and electric generator sectors, while residential, commercial, and transportation sectors have distributor tariffs defined only for the core market, since noncore customer consumption in these sectors is assumed to be insignificant and set to zero. The core transportation sector is composed of two categories of compressed natural gas (CNG) consumers (fleet vehicles and personal vehicles); therefore, separate distributor tariffs are developed for each of these two categories.

For the residential, commercial, industrial, and electric generation sectors distributor tariffs are based on econometrically estimated equations and are driven in part by sectoral consumption levels.[72] This general approach was taken since data are not reasonably obtainable to develop a detailed cost-based accounting methodology similar to the approach used for interstate pipeline tariffs in the Pipeline Tariff Submodule. Distribution charges for CNG in vehicles are set to the sum of historical tariffs for delivering natural gas to refueling stations, federal and state motor fuels taxes and credits, and estimates of dispensing charges. The specific methodologies used to calculate each sector's distributor tariffs are discussed in the remainder of this chapter.

Residential and Commercial Sectors

Residential and commercial distributor tariffs are projected using econometrically estimated equations. The primary explanatory variables are floorspace and commercial natural gas consumption per floorspace for the commercial tariff, and number of households and natural gas consumption per household for the residential sector tariff. In both cases distributor tariffs are estimated separately for the peak and off-peak periods, as follows:

[71] It is not unusual for these "markups" to be negative.

[72] Historical distributor tariffs for a sector in a particular region/season can be estimated by taking the difference between the average sectoral delivered price and the average city gate price in the region/season (Appendix E, HCGPR).

Residential peak

$$\begin{aligned}\mathrm{DTAR_SF}_{s=1,r,n=1} &= e^{\mathrm{PRSREGPK19}_{r,n=1}} * \mathrm{NUMRS}_{r,t}^{0.162972} * \\ &\left(\frac{\mathrm{BASQTY_SF}_{s=1,r,n=1} + \mathrm{BASQTY_SI}_{s=1,r,n=1}}{\mathrm{NUMRS}_{r,t}}\right)^{-0.607267} * \\ &\mathrm{DTAR_SFPREV}_{s=1,r,n=1}^{0.231296} * e^{(-0.231296*\mathrm{PRSREGPK19}_{r,n=1})} * \mathrm{NUMRS}_{r,t-1}^{-0.231296*0.162972} * \\ &\left(\frac{\mathrm{BASQTY_SFPREV}_{s=1,r,n=1} + \mathrm{BASQTY_SIPREV}_{s=1,r,n=1}}{\mathrm{NUMRS}_{r,t-1}}\right)^{(-0.231296*-0.607267)}\end{aligned} \quad (107)$$

Residential off-peak

$$\begin{aligned}\mathrm{DTAR_SF}_{s=1,r,n=2} &= e^{\mathrm{PRSREGPK19}_{r,n=2}} * \mathrm{NUMRS}_{r,t}^{0.282301} * \\ &\left(\frac{\mathrm{BASQTY_SF}_{s=1,r,n=2} + \mathrm{BASQTY_SI}_{s=1,r,n=2}}{\mathrm{NUMRS}_{r,t}}\right)^{-0.814968} * \\ &\mathrm{DTAR_SFPREV}_{s=1,r,n=2}^{0.231296} * e^{(-0.202612*\mathrm{PRSREGPK19}_{r,n=2})} * \mathrm{NUMRS}_{r,t-1}^{-0.202612*0.282301} * \\ &\left(\frac{\mathrm{BASQTY_SFPREV}_{s=1,r,n=2} + \mathrm{BASQTY_SIPREV}_{s=1,r,n=2}}{\mathrm{NUMRS}_{r,t-1}}\right)^{(-0.202612*-0.814968)}\end{aligned} \quad (108)$$

Commercial peak

$$\begin{aligned}\mathrm{DTAR_SF}_{s=2,r,n=2} &= e^{\mathrm{PCMREGPK13}_{r,n=1}} * \mathrm{FLRSPC12}_{r,t}^{0.218189} * \\ &\left(\frac{\mathrm{BASQTY_SF}_{s=2,r,n=1} + \mathrm{BASQTY_SI}_{s=2,r,n=1}}{\mathrm{FLRSPC12}_{r,t}}\right)^{-0.217322} * \\ &\mathrm{DTAR_SFPREV}_{s=2,r,n=1}^{0.284608} * e^{(-0.284608*\mathrm{PCMREGPK13}_{r,n=1})} * \mathrm{FLRSPC12}_{r,t-1}^{-0.284608*0.218189} \\ &\left(\frac{\mathrm{BASQTY_SFPREV}_{s=2,r,n=1} + \mathrm{BASQTY_SIPREV}_{s=2,r,n=1}}{\mathrm{FLRSPC12}_{r,t-1}}\right)^{(-0.284608*-0.217322)}\end{aligned} \quad (109)$$

Commercial off-peak

$$DTAR_SF_{s=2,r,n=2} = e^{PCMREGPK13_{r,n=2}} * FLRSPC12_{r,t}^{0.530831} * \left(\frac{BASQTY_SF_{s=2,r,n=2} + BASQTY_SI_{s=2,r,n=2}}{FLRSPC12_{r,t}}\right)^{-0.613588} * DTAR_SFPREV_{s=2,r,n=2}^{0.166956} * e^{(-0.166956*PCMREGPK13_{r,n=2})} * FLRSPC12_{r,t-1}^{-0.166956*0.530831} \left(\frac{BASQTY_SFPREV_{s=2,r,n=2} + BASQTY_SIPREV_{s=2,r,n=2}}{FLRSPC12_{r,t-1}}\right)^{(-0.166956*-0.613588)} \quad (110)$$

where,

$$NUMRS_{r,t} = oRSGASCUST_{cd,t} * RECS_ALIGN_r * NUM_REGSHR_r \quad (111)$$

and,

$$FLRSPC12_{r,t} = (MC_COMMFLSP_{1,cd,t} - MC_COMMFLSP_{8,cd,t}) * SHARE_r \quad (112)$$

where,

$DTAR_SF_{s,r,n}$ = core distributor tariff in current forecast year for sector s, region r, and network n (1987$/Mcf)

$DTAR_SFPREV_{s,r,n}$ = core distributor tariff in previous forecast year (1987$/Mcf). [For first forecast year set at the 2008 historical value.]

$BASQTY_SF_{s,r,n}$ = sector (s) level firm gas consumption for region r, and network n (Bcf)

$BASQTY_SI_{s,r,n}$ = sector (s) level nonfirm gas consumption for region r, and network n (Bcf) (assumed at 0 for residential and commercial)

$BASQTY_SFPREV_{s,r,n}$ = sector (s) level gas consumption for region r, and network n in previous year (Bcf) (assumed at 0 for residential and commercial)

$BASQTY_SIPREV_{s,r,n}$ = sector (s) level nonfirm gas consumption for region r, and network n in previous year (Bcf)

$NUMRS$ = number of residential customers in year t

$PRSREGPK19_{r,n}$ = residential, regional, period specific, constant term (Table F6, Appendix F)

$PCMREGPK13_{r,n}$ = commercial, regional, peak specific, constant term (Table F7, Appendix F)

$oRSGASCUST_{cd,t-1}$ = number of residential gas customers by census division in the previous forecast year (from NEMS residential demand module)

$RECS_ALIGN_r$ = factor to align residential customer count data from EIA's 2005 Residential Consumption Survey (RECS), the data on which oRSGASCUST is based, with similar data from the EIA's Natural Gas Annual, the data on which the DTAR_SF estimation is based.

NUM_REGSHR_r = share of residential customers in NGTDM region r relative to the number in the larger or equal sized associated census division, set to values in last historical year, 2008. (fraction, Appendix E)

$FLRSPC12_r$ = commercial floorspace by NGTDM region (total net of for manufacturing) (billion square feet)
$MC_COMMFLSP_{1,cd,t}$ = commercial floorspace by Census Division (total, including manufacturing)
$MC_COMMFLSP_{8,cd,t}$ = commercial floorspace by Census Division (manufacturing)
$SHARE_r$ = assumed fraction of the associated census division's commercial floorspace within each of the 12 NGTDM regions based on population data (1.0, 1.0, 1.0, 1.0, 0.66, 1.0, 1.0, 0.59, 0.24, 0.34, 0.41, 0.75)
s = sector (=1 for residential, =2 for commercial)
cd = census division
r = region (12 NGTDM regions)
n = network (=1 for peak, =2 for off-peak)
t = forecast year (e.g., 2010)

Parameter values and details about the estimation of these equations can be found in Tables F6 and F7 of Appendix F.

Industrial Sector

For the industrial sector, a single distributor tariff (i.e., no distinction between core and noncore) is estimated for each season and region as a function of the industrial consumption level in that season and region. Next, core seasonal tariffs are set by assuming a differential between the core price and the estimated distributor tariff for the season and region, based on historical estimates. The noncore price is set to insure that the quantity-weighted average of the core and noncore price in a season and region will equal the originally estimated tariff for that season and region. Historical prices for the industrial sector are estimated based on the data that are available from the Manufacturing Energy Consumption Survey (MECS) (Table F5, Appendix F). The industrial prices within EIA's Natural Gas Annual only represent industrial customers who purchase gas through their local distribution company, a small percentage of the total; whereas the prices in the MECS represent a much larger percentage of the total industrial sector. The equation for the single seasonal/regional industrial distributor tariff follows:

$$\begin{aligned} TAR = {} & 0.199135 + PINREG15_r + PIN_REGPK15_{r,n} + \\ & (-0.000317443 * QCUR_n) + (0.423561 * TARLAG_n) \\ & - 0.423561 * [0.199135 + PIN_REG15_r + PIN_REGPK15_{r,n} + \\ & (-0.000317443 * QLAG_n)] \end{aligned} \quad (113)$$

The core and noncore distributor tariffs are set using:

$$DTAR_SF_{s=3,r,n} = TAR + FDIFF_{cr} \quad (114)$$

$$DTAR_SI_{s=3.r,.n} = \frac{(TAR * QCUR_n) - (DTAR_SF_{s=3,r,n} * BASQTY_SF_{s=3,r,n})}{BASQTY_SI_{s=3,r,n}} \quad (115)$$

where,

TAR = seasonal distributor tariff for industrial sector in region r (87$/Mcf)

$TARLAG_n$ = seasonal distributor tariff for the industrial sector (s=3) in region r in the previous forecast year (87$/Mcf)

$FDIFF_{cr}$ = historical average difference between core and average industrial price (1987$/Mcf, Appendix E)

PIN_REG15_r = estimated constant term (Table F4, Appendix F)

$PIN_REGPK15_{r,n}$ = estimated coefficient, set to zero for the off-peak period and for any region where the coefficient is not statistically significant

$DTAR_SF_{n,s,r}$ = seasonal distributor tariff for the core industrial sector (s=3) in region r (87$/Mcf)

$DTAR_SI_{n,s,r}$ = seasonal distributor tariff for the noncore industrial sector (s=3) in region r (87$/Mcf)

$DTAR_SFPREV_{n,s,r}$ = seasonal distributor tariff for the core industrial sector (s=3) in region r (87$/Mcf) in the previous forecast year [In the first forecast year set to the estimated average historical value from 2006 to 2009 [Table F5, Appendix F] (87$/Mcf)]

$BASQTY_SF_{n,s=3,r}$ = seasonal core natural gas consumption for industrial sector(s=3) in the current forecast year (Bcf)

$BASQTY_SI_{n,s=3,r}$ = seasonal noncore natural gas consumption for industrial sector (s=3) in the current forecast year (Bcf)

$QCUR_n$ = sum of BASQTY_SF and BASQTY_SI for industrial in a particular season and region

$QLAG_n$ = sum of BASQTY_SFPREV and BASQTY_SIPREV for industrial in a particular season and region, the value of QCUR in the last forecast year

s = end-use sector index (s=3 for industrial sector)

n = network (peak or off-peak)

r = NGTDM region

cr = the census region associated with the NGTDM region

Parameter values and details about the estimation of these two equations can be found in Table F4 and F5, Appendix F.

Electric Generation Sector

Distributor tariffs for the electric generation sector do not represent a charge imposed by a local distribution company; rather they represent the difference between the average city gate price in each NGTDM region and the natural gas price paid on average by electric generators in each NGTDM/EMM region, and are often negative. A single markup or tariff (i.e., no distinction between core and noncore) is projected for each season and region using econometrically estimated equations, as was done for the industrial sector. However, the current version of the

model (as used for *AEO2011*) assigns this same value to both the core and noncore segments.[73] The estimated equations for the distributor tariffs for electric generators are a function of natural gas consumption by the sector relative to consumption by the other sectors. The greater the electric consumption share, the greater the price difference between the electric sector and the average, as they will need to reserve more space on the pipeline system. The specific equations follow:

$$\begin{aligned} UDTAR_SF_{n,j} = {} & (-0.153777 + 0.0299295) + PELREG31_{n,j} + \\ & (0.000000704 * qelec_{n,j}) + (0.281378 * UDTAR_SFPREV_{n,j}) \\ & - 0.281378 * [(-0.153777 + 0.0299295) + PELREG31_{n,j} + \\ & (0.000000704 * qeleclag_{n,j})] \end{aligned} \quad (116)$$

where,

$$qelec_{n,j} = (BASUQTY_SF_{n,j} + BASUQTY_SI_{n,j}) * 1000 \quad (117)$$

$$qeleclag_{n,j} = (BASUQTY_SFPREV_{n,j} + BASUQTY_SIPREV_{n,j}) * 1000 \quad (118)$$

$UDTAR_SI_{n,j}$ = $UDTAR_SF_{n,j}$ for all n and j,

where,

$UDTAR_SF_{n,j}$ = seasonal core electric generation sector distributor tariff, current forecast year ($/Mcf)

$UDTAR_SI_{n,j}$ = seasonal noncore electric generation sector distributor tariff, current forecast year ($/Mcf)

$UDTAR_SFPREV_{n,j}$ = seasonal core electric generation sector distributor tariff, previous forecast year ($/Mcf)

$BASUQTY_SF_{n,j}$ = core electric generator gas consumption, current forecast year (Bcf)

$BASUQTY_SI_{n,j}$ = noncore electric generator gas consumption, current forecast year (Bcf)

$BASUQTY_SFPREV_{n,j}$ = core electric generator gas consumption in previous forecast year (Bcf)

$BASUQTY_SIPREV_{n,j}$ = noncore electric generator gas consumption in previous forecast year (Bcf)

$PELREG31_{n=1,j}$ = $PELREG31_j$ in code, regional constant terms for peak period (Table F8, Appendix F)

$PELREG31_{n=2,j}$ = $PELREG32_j$ in code, regional constant terms for off-peak period (Table F8, Appendix F)

n = network (peak=1 or off-peak=2)

j = NGTDM/EMM region (see chapter 2)

[73]This distinction was eliminated several years ago because of operational concerns in the Electricity Market Module. In addition, there are some remaining issues concerning the historical data necessary to generate separate price series for the two segments.

Parameter values and details about the estimation of these two equations can be found in Table F8, Appendix F.

Transportation Sector

Consumers of compressed natural gas (CNG) have been classified into two end-use categories within the core transportation sector: fleet vehicles and personal vehicles (i.e., CNG sold at retail). A distributor tariff is set for both categories to capture 1) the cost of the natural gas delivered to the dispensing station above the city gate price, 2) the per-unit cost or charge for dispensing the gas, and 3) federal and state motor fuels taxes and credits.

For both categories, the distribution charge for the CNG delivered to the station is based on the historical difference between the price reported for the transportation sector in EIA's *Natural Gas Annual* (which should reflect this delivered price) and the city gate price. Similarly federal and state motor fuels taxes are assumed to be the same for both categories and held constant in nominal dollars.[74] The Highway Bill of 2005 raised the motor fuels tax for CNG. [75] The model adjusts the distribution costs accordingly. A potential difference in the pricing for the two categories is the assumed per-unit dispensing charge. Currently the refueling options available for personal natural gas vehicles are largely limited to the same refueling facilities used by fleet vehicles. Therefore, the assumption in the model is that the dispensing charge will be similar for fleet and personal vehicles ($RETAIL_COST_2$) unless there is a step increase in the number of retail stations selling natural gas in response to an expected increase in the number of personal vehicles. In such a case, an additional markup is added to the natural gas price to personal vehicles to account for the profit of the builder (RET_MARK), as described below. The distributor tariffs for CNG vehicles are set as follows:

$$DTAR_TRFV_SF_{n,r} = \{HDTAR_SF_{n,s=4,r,EHISYR} * (1 - TRN_DECL)^{YR_DECL}\} + RETAIL_COST_2 + \frac{(STAX_r + FTAX)}{MC_PCWGDP_t / MC_PCWGDP_{87}} \quad (119)$$

$$DTAR_TRPV_SF_{n,r} = \{HDTAR_SF_{n,s=4,r,EHISYR} * (1 - TRN_DECL)^{YR_DECL}\} + RETAIL_COST_2 + CNG_RETAIL_MARKUP_r + \frac{(STAX_r + FTAX)}{MC_PCWGDP_t / MC_PCWGDP_{87}} \quad (120)$$

where,

[74]Motor vehicle fuel taxes are assumed constant in current year dollars throughout the forecast to reflect current laws. Within the model these taxes are specified in 1987 dollars.

[75]The Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU), Section 1113. The bill also allowed for an excise tax credit of $0.50 per gasoline gallon equivalent to be paid to the seller of the CNG through September of 2009. The model assumes that the subsidy will be passed through to consumers.

$DTAR_TRFV_SF_{n,r}$ = distributor tariff for the fleet vehicle transportation sector (87$/Mcf)

$DTAR_TRPV_SF_{n,r}$ = distributor tariff for the personal vehicle transportation sector (87$/Mcf)

$HDTAR_SF_{n,s,r,EHISYR}$ = historical (2009) distributor tariff for the transportation sector to deliver the CNG to the station[76] (87$/ Mcf)

TRN_DECL = fleet vehicle distributor decline rate, set to zero for *AEO2011* (fraction, Appendix E)

YR_DECL = difference between the current year and the last historical year over which the decline rate is applied

$RETAIL_COST_2$ = assumed additional charge related to providing the dispensing service to customers, at a fleet refueling station (87$/Mcf, Appendix E)

$CNG_RETAIL_MARKUP_r$ = markup for natural gas sold at retail stations (described below)

$STAX_r$ = State motor vehicle fuel tax for CNG (current year $/Mcf, Appendix E)

FTAX = Federal motor vehicle fuel tax minus federal excise motor fuel credit for CNG (current year $/Mcf, Appendix E)

MC_PCWGDP_t = GDP conversion from current year dollars to 87 dollars [from the NEMS macroeconomic module]

n = network (peak or off-peak)

s = end-use sector index (s=4 for transportation sector)

r = NGTDM region

EHISYR = index defining last year that historical data are available

t = forecast year

A new algorithm was developed for *AEO2010* which projects whether construction of CNG fueling stations is economically viable in any of the NGTDM regions and, if so, sets the added charge that will result. In addition, the model provides the NEMS Transportation Sector Module with a projection of the fraction of retail refueling stations that sell natural gas. This is a key driver in the transportation module for projecting the number of compressed natural gas vehicles purchased and the resulting consumption level. While demand for CNG for personal vehicles is increased when fueling infrastructure is built, at the same time the viability of fueling infrastructure depends on sufficient demand to support it. A reduced form of the NEMS Transportation Sector Module was created for use in the NGTDM to estimate the increase in demand for CNG due to infrastructure construction, in order to project the revenue from a infrastructure building project, and then to assess its viability.

The basic algorithm involves 1) assuming a set increase in the number of stations selling CNG, 2) assuming CNG will be priced at a discount to the price of motor gasoline once it starts penetrating, 3) estimating the expected demand for CNG given the increased supply availability and price, 4) calculating the expected revenue per station that will cover capital expenditures

[76]EIA published, annual, State level data are used to set regional historical end-use prices for CNG vehicles. Since monthly data are not available for this sector, seasonal differentials for the industrial sector are applied to annual CNG data to approximate seasonal CNG prices.

(i.e., discounting for taxes, gas purchase costs, and other operating costs), 5) checking the revenue against infrastructure costs to determine viability, and 6) if viable, assuming the infrastructure will be added and the retail price changed accordingly.

The algorithm starts by testing the effects of building a large number of CNG stations (i.e., primarily by offering CNG at existing gasoline stations). The increase in availability that is tested is assumed to be a proportion of the number of gasoline stations in the region, as follows:

$$TOTPUMPS = NSTAT_r * (MAX_CNG_BUILD + CNGAVAIL_{t-1}) \quad (121)$$

where,

TOTPUMPS = the number of retail stations selling CNG in the region
$NSTAT_r$ = the number of gasoline stations in the region at the beginning of the projection period (Appendix E)
$CNGAVAIL_{t-1}$ = fraction of total retail refueling stations selling CNG last year
MAX_CNG_BUILD = assumed fraction of stations that can add CNG refueling this year (Appendix E).
r = census division
t = year

The assumed regional retail markup to cover capital costs if CNG infrastructure is built is set as follows:

$$TEST_MARKUP_r = minimum\{5.0, MAX_CNGMARKUP\} \quad (122)$$

where,

$$MAX_CNGMARKUP_r = 0.75 * \{PMGTR_{r,t-1} - (PGFTRPV_{r,t-1} - CNG_RETAIL_MARKUP_r)\} \quad (123)$$

where,

$TEST_MARKUP_r$ = assumed regional retail markup (87$/MMBtu)
$MAX_CNG_MARKUP_r$ = assumed maximum markup that can be added to base line cost of dispensing CNG to cover capital expenditures (87$/MMBtu) [Note: base line costs include taxes and fuel and basic operating costs]
$PMGTR_r$ = retail price of motor gasoline (87$/MMBtu)
PMGFTRPV = retail price of CNG (87$/MMBtu)
$CNG_RETAIL_MARKUP_r$ = retail CNG markup above base line costs added last year (87$/MMBtu)
0.75 = assumed economic rent that can be captured relative to the difference between the retail price of motor gasoline and the retail price of CNG (fraction)
5.0 = assumed minimum retail CNG markup (87$/MMBtu)

For each model year and region, the present value of projected revenue is determined with the following equation:

$$REVENUE = \sum_{n=1}^{CNG_HRZ} \frac{TEST_MARKUP_r * DEMAND * 1000000}{TOTPUMPS * (1 + CNG_WACC)^n} \quad (124)$$

where,

REVENUE = the net revenue per station (above the basic operating expenses) after infrastructure is added in the region (1987 dollars)

CNG_HRZ = the time horizon for the revenue calculation, corresponding to the number of years over which the capital investment is assumed to need to be recovered (Appendix E)

$TEST_MARKUP_r$ = assumed regional retail markup above baseline costs (87$/MMBtu)

DEMAND = estimated consumption of CNG by personal vehicles if the infrastructure is added and the implied retail price is charged (trillion BTU), described at the end of this section

TOTPUMPS = the number of retail stations selling CNG in the region

CNG_WACC = assumed weighted average cost of capital for financing the added CNG infrastructure (Appendix E)

The model compares the present value of the projected revenue per station from an infrastructure build to the assumed cost of a station (CNG_BUILDCOST, Appendix E) to make the decision of whether stations are built or not. The cost of a station reflects the estimated cost of building a single pumping location in an existing retrial refueling station, considering the tax value of depreciation and a payback number of years (CNG_HRZ, Appendix E) and an assumed weighted average cost of capital (CNG_WACC, Appendix E). If the revenue is sufficient in a region then the availability of CNG stations in that region are increased and the retail markup is set to the markup that was tested. The equations for new retail markup and availability when stations have been built are given in the following:

$$CNGAVAIL_{r,t} = CNGAVAIL_{r,t-1} + MAX_CNG_BUILD \quad (125)$$

$$RET_MARK_r = TEST_MARKUP \quad (126)$$

where,

$CNGAVAIL_{r,t}$ = fraction of regional retail refueling stations selling CNG

MAX_CNG_BUILD = incremental fraction of retail refueling stations selling CNG with added infrastructure in the year

RET_MARK_r = CNG retail markup above baseline costs (87$/MMBtu)

TEST_MARKUP = assumed CNG retail markup above baseline costs, based on the difference between baseline CNG costs and motor gasoline prices (87$/MMBtu)

r = Census Division

t = year

These variables stay at last year's values if no stations have been built. The retail markup by NGTDM region (CNG_RETAIL_MARKUP), as used in the transportation sector distributor tariff equation, is set by assigning the retail markup (RET_MARK) from the associated Census Division.

The demand response for CNG use in personal vehicles was estimated by doing multiple runs of the Transportation Sector Module. The key variable that was varied was the availability of CNG refueling stations. Test runs were made over a range of availability values for nine different cases. The cases were defined with three different motor gasoline to CNG price differentials (a maximum, a minimum, and the average between the two) in combination with three different CNG vehicle purchase subsidies ($0, $20,000, $40,000 in 2009 dollars per vehicle).[77] For each of the resulting nine sets of runs the CNG demand response in the Pacific Census Division was estimated as a function of station availability in a log-linear form with a constant term. The demand response in the Pacific Division was estimated by linearly interpolating between the points in the resulting three dimensional grid for a given availability (fraction of stations offering CNG), price differential between CNG and motor gasoline, and allowed subsidy for purchasing a CNG vehicle. The estimated consumption levels in the other Census Divisions were set by scaling the Pacific Division consumption based on size (as measured by total transportation energy demand) relative to the Pacific Division.

[77]Based on current laws and regulations in the *AEO2011* Reference Case, the subsidy is set to $0. A nonzero subsidy option was included for potential scenario analyses.

6. Pipeline Tariff Submodule Solution Methodology

The Pipeline Tariff Submodule (PTS) sets rates charged for storage services and interstate pipeline transportation. The rates developed are based on actual costs for transportation and storage services. These cost-based rates are used as a basis for developing tariff curves for the Interstate Transmission Submodule (ITS). The PTS tariff calculation is divided into two phases: an historical year initialization phase and a forecast year update phase. Each of these two phases includes the following steps: (1) determine the various components, in nominal dollars, of the total cost-of-service, (2) classify these components as fixed and variable costs based on the rate design (for transportation), (3) allocate these fixed and variable costs to rate components (reservation and usage costs) based on the rate design (for transportation), and (4) for transportation: compute rates for services during peak and off-peak time periods; for storage: compute annual regional tariffs. For the historical year phase, the cost of service is developed from historical financial data on 28 major U.S. interstate pipeline companies; while for the forecast year update phase the costs are estimated using a set of econometric equations and an accounting algorithm. The pipeline tariff calculations are described first, followed by the storage tariff calculations, and finally a description of the calculation of the tariffs for moving gas by pipeline from Alaska and from the MacKenzie Delta to Alberta. A general overview of the methodology for deriving rates is presented in the following box. The PTS system diagram is presented in **Figure 6-1**.

The purpose of the historical year initialization phase is to provide an initial set of transportation revenue requirements and tariffs. The last historical year for the PTS is currently 2006, which need not align with the last historical year for the rest of the NGTDM. Ultimately the ITS requires pipeline and storage tariffs; whether they are based on historical or projected financial data is mechanically irrelevant. The historical year information is developed from existing pipeline company transportation data. The historical year initialization process draws heavily on three databases: (1) a pipeline financial database (1990-2006) of 28 major interstate natural gas pipelines developed by Foster Associates,[83] (2) "a competitive profile of natural gas services" database developed by Foster Associates,[84] and (3) a pipeline capacity database developed by the former Office of Oil and Gas, EIA.[85] The first database represents the existing physical U.S. interstate pipeline and storage system, which includes production processing, gathering, transmission, storage, and other. The physical system is at a more disaggregate level than the NGTDM network. This database provides detailed company-level financial, cost, and rate base parameters. It contains information on capital structure, rate base, and revenue requirements by major line item of the cost of service for the historical years of the model. The second Foster database contains

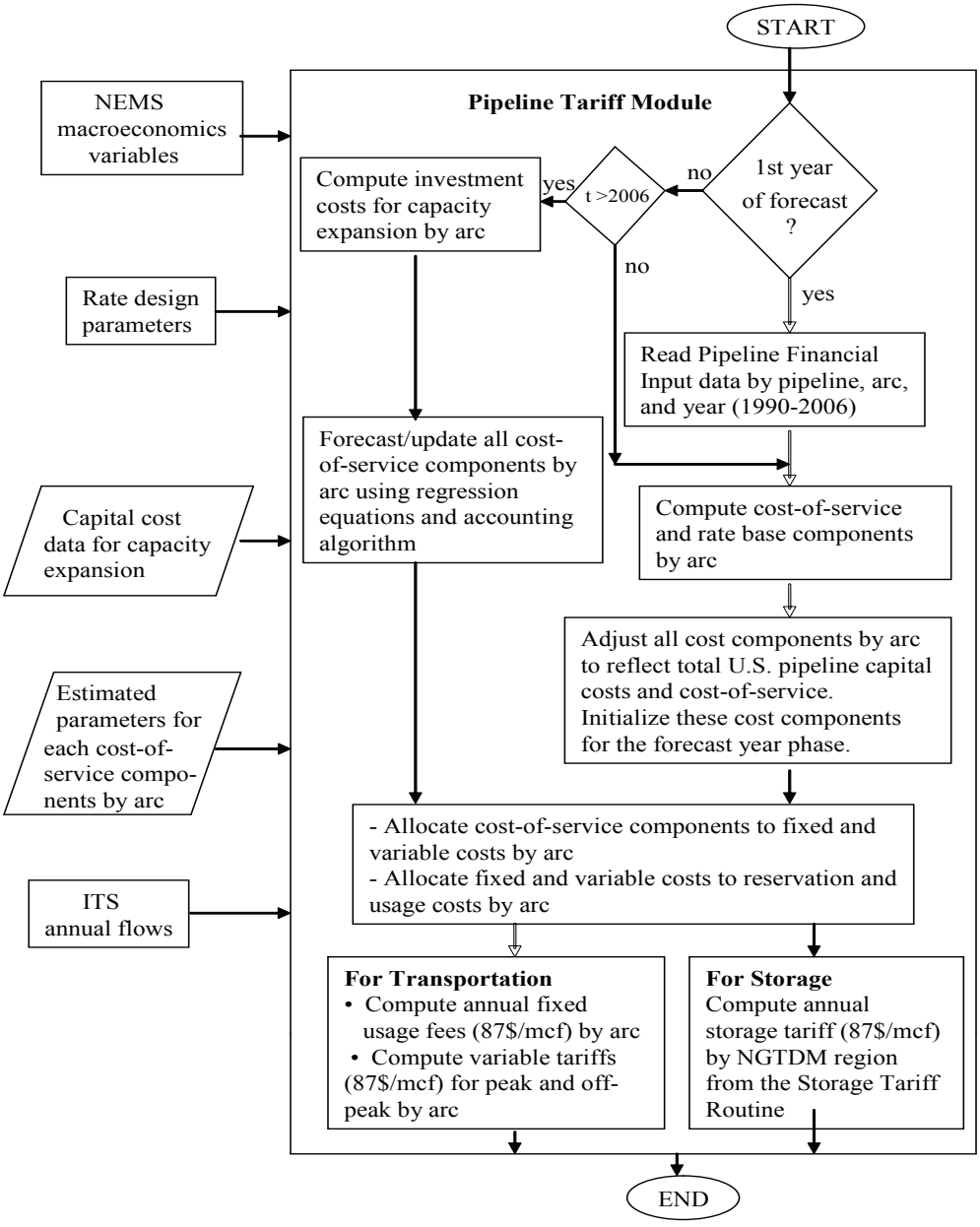
[83]Foster Financial Reports, 28 Major Interstate Natural Gas Pipelines, 2000, 2004 and 2007 Editions, Foster Associates, Inc., Bethesda, Maryland. The primary sources of data for these reports are FERC Form 2 and the monthly FERC Form 11 pipeline company filings. These reports can be purchased from Foster Associates.

[84]Competitive Profile of Natural Gas Services, Individual Pipelines, December 1997, Foster Associates, Inc., Bethesda, Maryland. Volumes III and IV of this report contain detailed information on the major interstate pipelines, including a pipeline system map, capacity, rates, gas plant accounts, rate base, capitalization, cost of service, etc. This report can be purchased from Foster Associates.

[85]A spreadsheet compiled by James Tobin of the Office of Oil and Gas containing historical and proposed state-to-state pipeline construction project costs, mileage, capacity levels and additions by year from 1996 to 2011, by pipeline company (data as of August 16, 2007).

detailed data on gross and net plant in service and depreciation, depletion, and amortization for individual plants (production processing and gathering plants, gas storage plants, gas transmission plants, and other plants) and is used to compute sharing factors by pipeline company and year to single out financial cost data for transmission plants from the "total plants" data in the first database.

Figure 6-1. Pipeline Tariff Submodule System Diagram



The third database contains information on pipeline financial construction projects by pipeline company, state-to-state transfer, and year (1996-2011). This database is used to determine factors to allocate the pipeline company financial data to the NGTDM interstate pipeline arcs based on capacity level in each historical year. These three databases are pre-processed offline to generate the pipeline transmission financial data by pipeline company, NGTDM interstate arc, and historical year (1990-2006) used as input into the PTS.

PTS Process for Deriving Rates

For Each Pipeline Arc

- Read historical financial database for 28 major interstate natural gas pipelines by pipeline company, arc, and historical year (1990-2006).

- Derive the total pipeline cost of service (TCOS)
  - Historical years
  - Aggregate pipeline TCOS items to network arcs
    - Adjust TCOS components to reflect all U.S. pipelines based on annual "Pipeline Economics" special reports in the Oil & Gas Journal
  - Forecast years
    - Include capital costs for capacity expansion
    - Estimate TCOS components from forecasting equations and accounting algorithm

- Allocate total cost of service to fixed and variable costs based on rate design

- Allocate costs to rate components (reservation and usage costs) based on rate design

- Compute rates for services for peak and off-peak time periods

For Each Storage Region:

- Derive the total storage cost of service (STCOS)

  - Historical years: read regional financial data for 33 storage facilities by node (NGTDM region) and historical year (1990-1998)
  - Forecast years:
    - Estimate STCOS components from forecasting equations and accounting algorithm
    - Adjust STCOS to reflect total U.S. storage facilities based on annual storage capacity data reported by EIA

- Compute annual regional storage rates for services

Historical Year Initialization Phase

The following section discusses two separate processes that occur during the historical year initialization phase: (1) the computation and initialization of the cost-of-service components, and (2) the computation of rates for services. The computation of historical year cost-of-service components and rates for services involves four distinct procedures as outlined in the above box and discussed below. Rates are calculated in nominal dollars and then converted to real dollars for use in the ITS.

Computation and Initialization of Pipeline Cost-of-Service Components

In the historical year initialization phase of the PTS, rates are computed using the following process: (Step 1) derivation and initialization of the total cost-of-service components, (Step 2) classification of cost-of-service components as fixed and variable costs, (Step 3) allocation of fixed and variable costs to rate components (reservation and usage costs) based on rate design, and (Step 4) computation of rates at the arc level for transportation services.

Step 1: Derivation and Initialization of the Total Cost-of-Service Components

The total cost-of-service for existing capacity on an arc consists of a just and reasonable return on the rate base plus total normal operating expenses. Derivations of return on rate base and total normal operating expenses are presented in the following subsections. The total cost of service is computed as follows:

$$TCOS_{a,t} = TRRB_{a,t} + TNOE_{a,t} \quad (127)$$

where,

$TCOS_{a,t}$ = total cost-of-service (dollars)
$TRRB_{a,t}$ = total return on rate base (dollars)
$TNOE_{a,t}$ = total normal operating expenses (dollars)
a = arc
t = historical year

Just and Reasonable Return. In order to compute the return portion of the cost-of-service at the arc level, the determination of capital structure and adjusted rate base is necessary. Capital structure is important because it determines the cost of capital to the pipeline companies associated with a network arc. The weighted average cost of capital is applied to the rate base to determine the return component of the cost-of-service, as follows:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \quad (128)$$

where,

$TRRB_{a,t}$ = total return on rate base after taxes (dollars)
$WAROR_{a,t}$ = weighted-average after-tax return on capital (fraction)
$APRB_{a,t}$ = adjusted pipeline rate base (dollars)
a = arc
t = historical year

In addition, the return on rate base $TRRB_{a,t}$ is broken out into the three components as shown below.

$$PFEN_{a,t} = \sum_{p} [(PFES_{a,p,t} / TOTCAP_{a,p,t}) * PFER_{a,p,t} * APRB_{a,p,t}] \quad (129)$$

$$CMEN_{a,t} = \sum_{p} [(CMES_{a,p,t} / TOTCAP_{a,p,t}) * CMER_{a,p,t} * APRB_{a,p,t}] \quad (130)$$

$$LTDN_{a,t} = \sum_{p} [(LTDS_{a,p,t} / TOTCAP_{a,p,t}) * LTDR_{a,p,t} * APRB_{a,p,t}] \quad (131)$$

such that,

$$TRRB_{a,t} = (PFEN_{a,t} + CMEN_{a,t} + LTDN_{a,t}) \quad (132)$$

where,

$PFEN_{a,t}$ = total return on preferred stock (dollars)
$PFES_{a,p,t}$ = value of preferred stock (dollars)
$TOTCAP_{a,p,t}$ = total capitalization (dollars)
$PFER_{a,p,t}$ = coupon rate for preferred stock (fraction) [read as D_PFER]
$APRB_{a,p,t}$ = adjusted pipeline rate base (dollars) [read as D_APRB]
$CMEN_{a,t}$ = total return on common stock equity (dollars)
$CMES_{a,p,t}$ = value of common stock equity (dollars)
$CMER_{a,p,t}$ = common equity rate of return (fraction) [read as D_CMER]
$LTDN_{a,t}$ = total return on long-term debt (dollars)
$LTDS_{a,p,t}$ = value of long-term debt (dollars)
$LTDR_{a,p,t}$ = long-term debt rate (fraction) [read as D_LTDR]
p = pipeline company
a = arc
t = historical year

Note that the first terms (fractions) in parentheses on the right hand side of equations 129 to 131 represent the capital structure ratios for each pipeline company associated with a network arc. These fractions are computed exogenously and read in along with the rates of return and the adjusted rate base. The total returns on preferred stock, common equity, and long-term debt at the arc level are computed immediately after all the input variables are read in. The capital structure ratios are exogenously determined as follows:

$$GPFESTR_{a,p,t} = PFES_{a,p,t} / TOTCAP_{a,p,t} \quad (133)$$

$$GCMESTR_{a,p,t} = CMES_{a,p,t} / TOTCAP_{a,p,t} \quad (134)$$

$$GLTDSTR_{a,p,t} = LTDS_{a,p,t} / TOTCAP_{a,p,t} \quad (135)$$

where,

$GPFESTR_{a,p,t}$ = capital structure ratio for preferred stock for existing pipeline (fraction) [read as D_GPFES]

$GCMESTR_{a,p,t}$ = capital structure ratio for common equity for existing pipeline (fraction) [read as D_GCMES]
$GLTDSTR_{a,p,t}$ = capital structure ratio for long-term debt for existing pipeline (fraction) [read as D_GLTDS]
$PFES_{a,p,t}$ = value of preferred stock (dollars)
$CMES_{a,p,t}$ = value of common stock (dollars)
$LTDS_{a,p,t}$ = value of long-term debt (dollars)
$TOTCAP_{a,p,t}$ = total capitalization (dollars), equal to the sum of value of preferred stock, common stock equity, and long-term debt
p = pipeline company
a = arc
t = historical year

In the financial database, the estimated capital (capitalization) for each interstate pipeline is by definition equal to its adjusted rate base. Hence, the estimated capital $TOTCAP_{a,p,t}$ defined in the above equations is equal to the adjusted rate base $APRB_{a,p,t}$.

$$TOTCAP_{a,p,t} = APRB_{a,p,t} \quad (136)$$

where,

$TOTCAP_{a,p,t}$ = total capitalization (dollars)
$APRB_{a,p,t}$ = adjusted rate base (dollars)
a = arc
p = pipeline company
t = historical year

Substituting the adjusted rate base $APRB_{a,t}$ for the estimated capital $TOTCAP_{a,t}$ in equations 133 to 135, the values of preferred stock, common stock, and long-term debt by pipeline and arc can be computed by applying the capital structure ratios to the adjusted rate base, as follows:

$$\begin{aligned} PFES_{a,p,t} &= GPFESTR_{a,p,t} * APRB_{a,p,t} \\ CMES_{a,p,t} &= GCMESTR_{a,p,t} * APRB_{a,p,t} \\ LTDS_{a,p,t} &= GLTDSTR_{a,p,t} * APRB_{a,p,t} \\ GPFESTR_{a,p,t} &+ GCMESTR_{a,p,t} + GLTDSTR_{a,p,t} = 1.0 \end{aligned} \quad (137)$$

where,

$PFES_{a,p,t}$ = value of preferred stock in nominal dollars
$CMES_{a,p,t}$ = value of common equity in nominal dollars
$LTDS_{a,p,t}$ = long-term debt in nominal dollars
$GPFESTR_{a,p,t}$ = capital structure ratio for preferred stock for existing pipeline (fraction)
$GCMESTR_{a,p,t}$ = capital structure ratio of common stock for existing pipeline (fraction)
$GLTDSTR_{a,p,t}$ = capital structure ratio of long term debt for existing pipeline (fraction)

$APRB_{a,p,t}$ = adjusted rate base (dollars)
p = pipeline
a = arc
t = forecast year

The cost of capital at the arc level ($WAROR_{a,t}$) is computed as the weighted average cost of capital for preferred stock, common stock equity, and long-term debt for all pipeline companies associated with that arc, as follows:

$$WAROR_{a,t} = \sum_{p} [(PFES_{a,p,t} * PFER_{a,p,t} + CMES_{a,p,t} * CMER_{a,p,t} + LTDS_{a,p,t} * LTDR_{a,p,t})] / APRB_{a,t} \quad (138)$$

$$APRB_{a,t} = PFES_{a,t} + CMES_{a,t} + LTDS_{a,t} \quad (139)$$

where,

$WAROR_{a,t}$ = weighted-average after-tax return on capital (fraction)
$PFES_{a,p,t}$ = value of preferred stock (dollars)
$PFER_{a,p,t}$ = preferred stock rate (fraction)
$CMES_{a,p,t}$ = value of common stock equity (dollars)
$CMER_{a,p,t}$ = common equity rate of return (fraction)
$LTDS_{a,p,t}$ = value of long-term debt (dollars)
$LTDR_{a,p,t}$ = long-term debt rate (fraction)
$APRB_{a,p,t}$ = adjusted rate base (dollars)
p = pipeline
a = arc
t = historical year

The adjusted rate base by pipeline and arc is computed as the sum of net plant in service and total cash working capital (which includes plant held for future use, materials and supplies, and other working capital) minus accumulated deferred income taxes. This rate base is computed offline and read in by the PTS. The computation is as follows:

$$APRB_{a,p,t} = NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t} \quad (140)$$

where,

$APRB_{a,p,t}$ = adjusted rate base (dollars)
$NPIS_{a,p,t}$ = net capital cost of plant in service (dollars) [read as D_NPIS]
$CWC_{a,p,t}$ = total cash working capital (dollars) [read as D_CWC]
$ADIT_{a,p,t}$ = accumulated deferred income taxes (dollars) [read as D_ADIT]
p = pipeline company
a = arc
t = historical year

The net plant in service by pipeline and arc is the original capital cost of plant in service minus the accumulated depreciation. It is computed offline and then read in by the PTS. The computation is as follows:

$$NPIS_{a,p,t} = GPIS_{a,p,t} - ADDA_{a,p,t} \quad (141)$$

where,

$NPIS_{a,p,t}$ = net capital cost of plant in service (dollars)
$GPIS_{a,p,t}$ = original capital cost of plant in service (dollars) [read as D_GPIS]
$ADDA_{a,p,t}$ = accumulated depreciation, depletion, and amortization (dollars) [read as D_ADDA]
p = pipeline company
a = arc
t = historical year

The adjusted rate base at the arc level is computed as follows:

$$APRB_{a,,t} = \sum_{p} APRB_{a,p,t} = \sum_{p} (NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t}) = (NPIS_{a,t} + CWC_{a,t} - ADIT_{a,t}) \quad (142)$$

with,

$$NPIS_{a,,t} = \sum_{p} (GPIS_{a,p,t} - ADDA_{a,p,t}) = (GPIS_{a,t} - ADDA_{a,t}) \quad (143)$$

where,

$APRB_{a,p,t}$ = adjusted rate base (dollars) at the arc level
$NPIS_{a,p,t}$ = net capital cost of plant in service (dollars) at the arc level
$CWC_{a,t}$ = total cash working capital (dollars) at the arc level
$ADIT_{a,t}$ = accumulated deferred income taxes (dollars) at the arc level
$GPIS_{a,p,t}$ = original capital cost of plant in service (dollars) at the arc level
$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization (dollars) at the arc level
p = pipeline company
a = arc
t = historical year

Total Normal Operating Expenses. Total normal operating expense line items include depreciation, taxes, and total operating and maintenance expenses. Total operating and maintenance expenses include administrative and general expenses, customer expenses, and other operating and maintenance expenses. In the PTS, taxes are disaggregated further into Federal, State, and other taxes and deferred income taxes. The equation for total normal operating expenses at the arc level is given as follows:

$$TNOE_{a,t} = \sum_{p} (DDA_{a,p,t} + TOTAX_{a,p,t} + TOM_{a,p,t}) \quad (144)$$

where,

$TNOE_{a,t}$ = total normal operating expenses (dollars)
$DDA_{a,p,t}$ = depreciation, depletion, and amortization costs (dollars) [read as D_DDA]

$TOTAX_{a,p,t}$ = total Federal and State income tax liability (dollars)
$TOM_{a,p,t}$ = total operating and maintenance expense (dollars) [read as D_TOM]
p = pipeline
a = arc
t = historical year

Depreciation, depletion, and amortization costs, and total operating and maintenance expense are available directly from the financial database. The equations to compute these costs at the arc level are as follows:

$$DDA_{a,t} = \sum_{p} DDA_{a,p,t} \quad (145)$$

$$TOM_{a,t} = \sum_{p} TOM_{a,p,t} \quad (146)$$

Total taxes at the arc level are computed as the sum of Federal and State income taxes, other taxes, and deferred income taxes, as follows:

$$TOTAX_{a,t} = \sum_{p} (FSIT_{a,p,t} + OTTAX_{a,p,t} + DIT_{a,p,t}) \quad (147)$$

$$FSIT_{a,t} = \sum_{p} FSIT_{a,p,t} = \sum_{p} (FIT_{a,p,t} + SIT_{a,p,t}) \quad (148)$$

where,

$TOTAX_{a,t}$ = total Federal and State income tax liability (dollars)
$FSIT_{a,p,t}$ = Federal and State income tax (dollars)
$OTTAX_{a,p,t}$ = all other taxes assessed by Federal, State, or local governments except income taxes and deferred income tax (dollars) [read as D_OTTAX]
$DIT_{a,p,t}$ = deferred income taxes (dollars) [read as D_DIT]
$FIT_{a,p,t}$ = Federal income tax (dollars)
$SIT_{a,p,t}$ = State income tax (dollars)
p = pipeline company
a = arc
t = historical year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the Federal tax rate. The after-tax profit at the arc level is determined as follows:

$$ATP_{a,t} = \sum_{p} (PFER_{a,p,t} * PFES_{a,p,t} + CMER_{a,p,t} * CMES_{a,p,t}) \quad (149)$$

where,

$ATP_{a,t}$ = after-tax profit (dollars) at the arc level
$PFER_{a,p,t}$ = preferred stock rate (fraction)
$PFES_{a,p,t}$ = value of preferred stock (dollars)

$CMER_{a,p,t}$ = common equity rate of return (fraction)
$CMES_{a,p,t}$ = value of common stock equity (dollars)
a = arc
t = historical year

and the Federal income taxes at the arc level are,

$$FIT_{a,t} = \frac{FRATE^{*} ATP_{a,t}}{(1. - FRATE)} \quad (150)$$

where,

$FIT_{a,t}$ = Federal income tax (dollars) at the arc level
FRATE = Federal income tax rate (fraction) (Appendix E)
$ATP_{a,t}$ = after-tax profit (dollars)

State income taxes are computed by multiplying the sum of taxable profit and the associated Federal income tax by a weighted-average State tax rate associated with each pipeline company. The weighted-average State tax rate is based on peak service volumes in each State delivered by the pipeline company. State income taxes at the arc level are computed as follows:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \quad (151)$$

where,

$SIT_{a,t}$ = State income tax (dollars) at the arc level
SRATE = average State income tax rate (fraction) (Appendix E)
$FIT_{a,t}$ = Federal income tax (dollars) at the arc level
$ATP_{a,t}$ = after-tax profits (dollars) at the arc level

Thus, total taxes at the arc level can be expressed by the following equation:

$$TOTAX_{a,t} = (FSIT_{a,t} + OTTAX_{a,t} + DIT_{a,t}) \quad (152)$$

where,

$TOTAX_{a,t}$ = total Federal and State income tax liability (dollars) at the arc level
$FSIT_{a,t}$ = Federal and State income tax (dollars) at the arc level
$OTTAX_{a,t}$ = all other taxes assessed by Federal, State, or local governments except income taxes and deferred income taxes (dollars), at the arc level
$DIT_{a,t}$ = deferred income taxes (dollars) at the arc level
a = arc
t = historical year

All other taxes and deferred income taxes at the arc level are expressed as follows:

$$OTTAX_{a,t} = \sum_{p} OTTAX_{a,p,t} \quad (153)$$

$$DIT_{a,t} = \sum_{p} DIT_{a,p,t} \quad (154)$$

Adjustment from 28 major pipelines to total U.S. Note that all cost-of-service and rate base components computed so far are based on the financial database of 28 major interstate pipelines. According to the U.S. natural gas pipeline construction and financial reports filed with the FERC and published in the Oil and Gas Journal,[86] there were more than 100 interstate natural gas pipelines operating in the United States in 2006. The total annual gross plant in service and operating revenues for all these pipelines are much higher than those for the 28 major interstate pipelines in the financial database. All the cost-of-service and rate base components at the arc level computed in the above sections are scaled up as follows: For the capital costs and adjusted rate base components,

$$\begin{aligned} GPIS_{a,t} &= GPIS_{a,t} * HFAC_GPIS_t \\ ADDA_{a,t} &= ADDA_{a,t} * HFAC_GPIS_t \\ NPIS_{a,t} &= NPIS_{a,t} * HFAC_GPIS_t \\ CWC_{a,t} &= CWC_{a,t} * HFAC_GPIS_t \\ ADIT_{a,t} &= ADIT_{a,t} * HFAC_GPIS_t \\ APRB_{a,t} &= APRB_{a,t} * HFAC_GPIS_t \end{aligned} \quad (155)$$

For the cost-of-service components,

$$\begin{aligned} PFEN_{a,t} &= PFEN_{a,t} * HFAC_REV_t \\ CMEN_{a,t} &= CMEN_{a,t} * HFAC_REV_t \\ LTDN_{a,t} &= LTDN_{a,t} * HFAC_REV_t \\ DDA_{a,t} &= DDA_{a,t} * HFAC_REV_t \\ FSIT_{a,t} &= FSIT_{a,t} * HFAC_REV_t \\ OTTAX_{a,t} &= OTTAX_{a,t} * HFAC_REV_t \\ DIT_{a,t} &= DIT_{a,t} * HFAC_REV_t \\ TOM_{a,t} &= TOM_{a,t} * HFAC_REV_t \end{aligned} \quad (156)$$

where,

$GPIS_{a,t}$ = original capital cost of plant in service (dollars)
$HFAC_GPIS_t$ = adjustment factor for capital costs to total U.S. (Appendix E)
$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization (dollars)
$NPIS_{a,t}$ = net capital cost of plant in service (dollars)
$CWC_{a,t}$ = total cash working capital (dollars)
$ADIT_{a,t}$ = accumulated deferred income taxes (dollars)
$APRB_{a,t}$ = adjusted pipeline rate base (dollars)
$PFEN_{a,t}$ = total return on preferred stock (dollars)

[86] *Pipeline Economics*, Oil and Gas Journal, 1994, 1995, 1997, 1999, 2001, 2002, 2003, 2004, 2005, 2006.

$HFAC_REV_t$ = adjustment factor for operation revenues to total U.S. (Appendix E)
$CMEN_{a,t}$ = total return on common stock equity (dollars)
$LTDN_{a,t}$ = total return on long-term debt (dollars)
$DDA_{a,t}$ = depreciation, depletion, and amortization costs (dollars)
$FSIT_{a,t}$ = Federal and State income tax (dollars)
$OTTAX_{a,t}$ = all other taxes assessed by Federal, State, or local governments except income taxes and deferred income taxes (dollars)
$DIT_{a,t}$ = deferred income taxes (dollars)
$TOM_{a,t}$ = total operations and maintenance expense (dollars)
a = arc
t = historical year

Except for the Federal and State income taxes and returns on capital, all the cost-of-service and rate base components computed at the arc level above are also used as initial values in the forecast year update phase that starts in 2007.

Step 2: Classification of Cost-of-Service Line Items as Fixed and Variable Costs

The PTS breaks each line item of the cost of service (computed in Step 1) into fixed and variable costs. Fixed costs are independent of storage/transportation usage, while variable costs are a function of usage. Fixed and variable costs are computed by multiplying each line item of the cost of service by the percentage of the cost that is fixed and the percentage of the cost that is variable. The classification of fixed and variable costs is defined by the user as part of the scenario specification. The classification of line item cost Ri to fixed and variable cost is determined as follows:

$$R_{i,f} = ALL_f * R_i / 100 \quad (157)$$

$$R_{i,v} = ALL_v * R_i / 100 \quad (158)$$

where,

$R_{i,f}$ = fixed cost portion of line item Ri (dollars)
ALL_f = percentage of line item Ri representing fixed cost
R_i = total cost of line item i (dollars)
$R_{i,v}$ = variable cost portion of line item Ri (dollars)
ALL_v = percentage of line item Ri representing variable cost
i = line item index
f,v = fixed or variable
100 = ALLf + ALLv

An example of this procedure is illustrated in **Table 6-1**.

The resulting fixed and variable costs at the arc level are obtained by summing all line items for each cost category from the above equations, as follows:

$$FC_a = \sum_i R_{i,f} \quad (159)$$

$$VC_a = \sum_i R_{i,v} \quad (160)$$

where,

FC_a = total fixed cost (dollars) at the arc level
VC_a = total variable cost (dollars) at the arc level
a = arc

Table 6-1. Illustration of Fixed and Variable Cost Classification

Cost of Service Line Item	Total (dollars)	Cost Allocation Factors (percent) Fixed	Variable	Cost Component (dollars) Fixed	Variable
Total Return					
Preferred Stock	1,000	100	0	1,000	0
Common Stock	30,000	100	0	30,000	0
Long-Term Debt	29,000	100	0	29,000	0
Normal Operating Expenses					
Depreciation	30,000	100	0	30,000	0
Taxes					
Federal Tax	25,000	100	0	25,000	0
State Tax	5,000	100	0	5,000	0
Other Tax	1,000	100	0	1,000	0
Deferred Income Taxes	1,000	100	0	1,000	0
	105,000	60	40	63,000	42,000
Total Operations & Maintenance					
Total Cost-of-Service	227,000			185,000	42,000

Step 3: Allocation of Fixed and Variable Costs to Rate Components

Allocation of fixed and variable costs to rate components is conducted only for transportation services because storage service is modeled in a more simplified manner using a one-part rate. The rate design to be used within the PTS is specified by input parameters, which can be modified by the user to reflect changes in rate design over time. The PTS allocates the fixed and variable costs computed in Step 2 to rate components as specified by the rate design. For transportation service, the components of the rate consist of a reservation and a usage fee. The reservation fee is a charge assessed based on the amount of capacity reserved. It typically is a monthly fee that does not vary with throughput. The usage fee is a charge assessed for each unit of gas that moves through the system.

The actual reservation and usage fees that pipelines are allowed to charge are regulated by the Federal Energy Regulatory Commission (FERC). How costs are allocated determines the extent of differences in the rates charged for different classes of customers for different types

of services. In general, if more fixed costs are allocated to usage fees, more costs are recovered based on throughput.

Costs are assigned either to the reservation fee or to the usage fee according to the rate design specified for the pipeline company. The rate design can vary among pipeline companies. Three typical rate designs are described in **Table 6-2**. The PTS provides two options for specifying the rate design. In the first option, a rate design for each pipeline company can be specified for each forecast year. This option permits different rate designs to be used for different pipeline companies while also allowing individual company rate designs to change over time. Since pipeline company data subsequently are aggregated to network arcs, the composite rate design at the arc-level is the quantity-weighted average of the pipeline company rate designs. The second option permits a global specification of the rate design, where all pipeline companies have the same rate design for a specific time period but can switch to another rate design in a different time period.

Table 6-2. Approaches to Rate Design

Modified Fixed Variable (Three-Part Rate)	Modified Fixed Variable (Two-Part Rate)	Straight Fixed Variable (Two-Part Rate)
• Two-part reservation fee. - Return on equity and related taxes are held at risk to achieving throughput targets by allocating these costs to the usage fee. Of the remaining fixed costs, 50 percent are recovered from a peak day reservation fee and 50 percent are recovered through an annual reservation fee.	• Reservation fee based on peak day requirements - all fixed costs except return on equity and related taxes recovered through this fee.	• One-part capacity reservation fee. All fixed costs are recovered through the reservation fee, which is assessed based on peak day capacity requirements.
• Variable costs allocated to the usage fee. In addition, return on equity and related taxes are also recovered through the usage fee.	• Variable costs plus return on equity and related taxes are recovered through the usage fee.	• Variable costs are recovered through the usage fee.

The allocation of fixed costs to reservation and usage fees entails multiplying each fixed cost line item of the total cost of service by the corresponding fixed cost rate design classification factor. A similar process is carried out for variable costs. This procedure is illustrated in **Tables 6-3a and 6-3b** and is generalized in the equations that follow. The classification of transportation line item costs $R_{i,f}$ and $R_{i,v}$ to reservation and usage cost is determined as follows:

$$R_{i,f,r} = ALL_{f,r} * R_{i,f} / 100 \quad (161)$$

$$R_{i,f,u} = ALL_{f,u} * R_{i,f} / 100 \quad (162)$$

$$R_{i,v,r} = ALL_{v,r} * R_{i,v} / 100 \quad (163)$$

$$R_{i,v,u} = ALL_{v,u} * R_{i,v} / 100 \quad (164)$$

Table 6-3a. Illustration of Allocation of Fixed Costs to Rate Components

Cost of Service Line Item	Total (dollars)	Allocation Factors (percent)		Cost Assigned to Rate Component (dollars)	
		Reservation	Usage	Reservation	Usage
Total Return					
Preferred Stock	1,000	100	0	0	1,000
Common Stock	30,000	100	0	0	30,000
Long-Term Debt	29,000	100	0	29,000	0
Normal Operating Expenses					
Depreciation	30,000	100	0	30,000	0
Taxes					
Federal Tax	25,000	0	100	0	25,000
State Tax	5,000	0	100	0	5,000
Other Tax	1,000	100	0	1,000	0
Deferred Income Taxes	1,000	100	0	1,000	0
Total Operations & Maintenance	63,000	100	0	63,000	0
Total Cost-of-Service	185,000			124,000	61,000

Table 6-3b. Illustration of Allocation of Variable Costs to Rate Components

Cost of Service Line Item	Total (dollars)	Allocation Factors (percent)		Cost Assigned to Rate Component (dollars)	
		Reservation	Usage	Reservation	Usage
Total Return					
Preferred Stock	0	0	100	0	0
Common Stock	0	0	100	0	0
Long-Term Debt	0	0	100	0	0
Normal Operating Expenses					
Depreciation	0	0	100	0	0
Taxes					
Federal Tax	0	0	100	0	0
State Tax	0	0	100	0	0
Other Tax	0	0	100	0	0
Deferred Income Taxes	0	0	100	0	0
Total Operations & Maintenance	42,000	0	100	0	42,000
Total Cost-of-Service	42,000			0	42,000

where,

R = line item cost (dollars)

ALL = percentage of reservation or usage line item R representing fixed or variable cost (Appendix E -- AFR, AVR, AFU=1-AFR, AVU=1-AVR)

100 = $ALL_{f,r} + ALL_{f,u}$

$100 = ALL_{v,r} + ALL_{v,u}$

i = line item number index
f = fixed cost index
v = variable cost index
r = reservation cost index
u = usage cost index

At this stage in the procedure, the line items comprising the fixed and variable cost components of the reservation and usage fees can be summed to obtain total reservation and usage components of the rates.

$$RCOST_a = \sum_i (R_{i,f,r} + R_{i,v,r}) \quad (165)$$

$$UCOST_a = \sum_i (R_{i,f,u} + R_{i,v,u}) \quad (166)$$

where,

$RCOST_a$ = total reservation cost (dollars) at the arc level
$UCOST_a$ = total usage cost (dollars) at the arc level
a = arc

After ratemaking Steps 1, 2 and 3 are completed for each arc by historical year, the rates are computed below.

Computation of Rates for Historical Years

The reservation and usage costs-of-service (RCOST and UCOST) developed above are used separately to develop two types of rates at the arc level: *variable tariffs* and *annual fixed usage fees*.

Variable Tariff Curves

Variable tariffs are proportional to reservation charges and are broken up into peak and off-peak time periods. Variable tariffs are derived directly from variable tariff curves which are developed based on reservation costs, utilization rates, annual flows, and other parameters.

In the PTS code, these variable tariff curves are defined by FUNCTION (NGPIPE_VARTAR) which is used by the ITS to compute the variable peak and off-peak tariffs by arc and by forecast year. The pipeline tariff curves are a function of peak or off-peak flow and are specified using a base point [price and quantity (PNOD, QNOD)] and an assumed price elasticity, as follows:

$$NGPIPE_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA_PIPE} \quad (167)$$

such that,

For peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * PKSHR_YR}{(QNOD_{a,t} * MC_PCWGDP_t)} \quad (168)$$

$$QNOD_{a,t} = PT\ NETFLOW_{a,t} \quad (169)$$

For off-peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR_YR)}{(QNOD_{a,t} * MC_PCWGDP_t)} \quad (170)$$

$$QNOD_{a,t} = PT\ NETFLOW_{a,t} \quad (171)$$

where,

$NGPIPE_VARTAR_{a,t}$ = function to define pipeline tariffs (87$/Mcf)
$PNOD_{a,t}$ = base point, price (87$/Mcf)
$QNOD_{a,t}$ = base point, quantity (Bcf)
$Q_{a,t}$ = flow along pipeline arc (Bcf), dependent variable for the function
$ALPHA_PIPE$ = price elasticity for pipeline tariff curve for current capacity
$RCOST_{a,t}$ = reservation cost-of-service (dollars)
$PTNETFLOW_{a,t}$ = natural gas network flow (throughput, Bcf)
$PKSHR_YR$ = portion of the year represented by the peak season (fraction)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = historical year

Annual Fixed Usage Fees

The annual fixed usage fees (volumetric charges) are derived directly from the usage costs, utilization rates for peak and off-peak time periods, and annual arc capacity. These fees are computed as the average fees over each historical year, as follows:

$$FIXTAR_{a,t} = UCOST_{a,t} / [(PKSHR_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + (1.0 - PKSHR_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC_PCWGDP_t] \quad (172)$$

where,

$FIXTAR_{a,t}$ = annual fixed usage fees for existing and new capacity (87$/Mcf)
$UCOST_{a,t}$ = annual usage cost of service for existing and new capacity (dollars)

$PKSHR_YR$ = portion of the year represented by the peak season (fraction)
$PTPKUTZ_{a,t}$ = peak pipeline utilization (fraction)
$PTCURPCAP_{a,t}$ = current pipeline capacity (Bcf)
$PTOPUTZ_{a,t}$ = off-peak pipeline utilization (fraction)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = historical year

Canadian Tariffs

In the historical year phase, Canadian tariffs are set to the historical differences between the import prices and the Western Canada Sedimentary Basin (WCSB) wellhead price.

Computation of Storage Rates

The annual storage tariff for each NGTDM region and year is defined as a function of storage flow and is specified using a base point [price and quantity (PNOD, QNOD)] and an assumed price elasticity, as follows:

$$X1NGSTR_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA_STR} \quad (173)$$

such that,

$$PNOD_{r,t} = \frac{STCOS_{r,t}}{(MC_PCWGDP_t * QNOD_{r,t} * 1{,}000{,}000.)} * \frac{}{STRATIO_{r,t} * STCAP_ADJ_{r,t} * ADJ_STR} \quad (174)$$

$$QNOD_{r,t} = PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \quad (175)$$

where,

$X1NGSTR_VARTAR_{r,t}$ = function to define storage tariffs (87$/Mcf)
$Q_{r,t}$ = peak period net storage withdrawals (Bcf)
$PNOD_{r,t}$ = base point, price (87$/Mcf)
$QNOD_{r,t}$ = base point, quantity (Bcf)
$ALPHA_STR$ = price elasticity for storage tariff curve (ratio, Appendix E)

$STCOS_{r,t}$ = existing storage capacity cost of service, computed from historical cost-of-service components
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
$STRATIO_{r,t}$ = portion of revenue requirement obtained by moving gas from the off-peak to the peak period (fraction, Appendix E)
$STCAP_ADJ_{r,t}$ = adjustment factor for the cost of service to total U.S. (ratio), defined as annual storage working gas capacity divided by

Foster storage working gas capacity
ADJ_STR = storage tariff curve adjustment factor (fraction, Appendix E)
$PTSTUTZ_{r,t}$ = storage utilization (fraction)
$PTCURPSTR_{r,t}$ = annual storage working gas capacity (Bcf)
r = NGTDM region
t = historical year

Forecast Year Update Phase

The purpose of the forecast year update phase is to project, for each arc and subsequent year of the forecast period, the cost-of-service components that are used to develop rates for the peak and off-peak periods. For each year, the PTS forecasts the adjusted rate base, cost of capital, return on rate base, depreciation, taxes, and operation and maintenance expenses. The forecasting relationships are discussed in detail below.

After all of the components of the cost-of-service at the arc level are forecast, the PTS proceeds to: (1) classify the components of the cost of service as fixed and variable costs, (2) allocate fixed and variable costs to rate components (reservation and usage costs) based on the rate design, and (3) compute arc-specific rates (variable and fixed tariffs) for peak and off-peak periods.

Investment Costs for Generic Pipelines

The PTS projects the capital costs to expand pipeline capacity at the arc level, as opposed to determining the costs of expansion for individual pipelines. The PTS represents arc-specific generic pipelines to generate the cost of capacity expansion by arc. Thus, the PTS tracks costs attributable to capacity added during the forecast period separately from the costs attributable to facilities in service in the historical years. The PTS estimates the capital costs associated with the level of capacity expansion forecast by the ITS in the previous forecast year based on exogenously specified estimates for the average pipeline capital costs at the arc level ($AVG_CAPCOST_a$) associated with expanding capacity for compression, looping, and new pipeline. These average capital costs per unit of expansion (2005 dollars per Mcf) were computed based on a pipeline construction project cost database[87] compiled by the Office of Oil and Gas. These costs are adjusted for inflation from 2007 throughout the forecast period (i.e., they are held constant in real terms).

The average capital cost to expand capacity on a network arc is estimated given the level of capacity additions in year t provided by the ITS and the associated assumed average unit capital cost. This average unit capital cost represents the investment cost for a generic pipeline associated with a given arc, as follows:

$$CCOST_{a,t} = AVG_CAPCOST_a * MC_PCWGDP_t / MC_PCWGDP_{2000} \quad (176)$$

[87] A spreadsheet compiled by James Tobin of EIA's Office of Oil and Gas containing historical and proposed state-to-state pipeline construction project costs, mileage, and capacity levels and additions by year from 1996 to 2011, by pipeline company (data as of August 16, 2007).

where,

$CCOST_{a,t}$ = average pipeline capital cost per unit of expanded capacity (nominal dollars per Mcf)

$AVG_CAPCOST_a$ = average pipeline capital cost per unit of expanded capacity in 2000 dollars per Mcf (Appendix E, AVGCOST)

MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)

a = arc

t = forecast year

The new capacity expansion expenditures allowed in the rate base within a forecast year are derived from the above average unit capital cost and the amount of incremental capacity additions determined by the ITS for each arc, as follows:

$$NCAE_{a,t} = CCOST_{a,t} * CAPADD_{a,t} * 1{,}000{,}000 * (1 + PCNT_R) \quad (177)$$

where,

$NCAE_{a,t}$ = capital cost to expand capacity on a network arc (dollars)

$CCOST_{a,t}$ = average capital cost per unit of expansion (dollars per Mcf)

$CAPADD_{a,t}$ = capacity additions for an arc as determined in the ITS (Bcf/yr)

PCNT_R = assumed average percentage (fraction) for pipeline replacement costs (Appendix E)

t = forecast year

To account for additional costs due to pipeline replacements, the PTS increases the capital costs to expand capacity by a small percentage (PCNT_R). Once the capital cost of new plant in service is computed by arc in year t, this amount is used in an accounting algorithm for the computation of gross plant in service for new capacity expansion, along with its depreciation, depletion, and amortization. These will in turn be used in the computation of updated cost-of-service components for the existing and new capacity for an arc.

Forecasting Cost-of-Service [88]

The primary purpose in forecasting cost-of-service is to capture major changes in the composition of the revenue requirements and major changes in cost trends through the forecast period. These changes may be caused by capacity expansion or maintenance and life extension of nearly depreciated plants, as well as by changes in the cost and availability of capital.

The projection of the cost-of-service is approached from the viewpoint of a long-run marginal cost analysis for gas pipeline systems. This differs from the determination of cost-of-service for the purpose of a rate case. Costs that are viewed as fixed for the purposes of a rate case actually vary in the long-run with one or more external measures of size or activity levels in the industry. For example, capital investments for replacement and refurbishment of existing facilities are a long-run marginal cost of the pipeline system. Once in place,

[88] All cost components in the forecast equations in this section are in nominal dollars, unless explicitly stated otherwise.

however, the capital investments are viewed as fixed costs for the purposes of rate cases. The same is true of operations and maintenance expenses that, except for short-run variable costs such as fuel, are most commonly classified as fixed costs in rate cases. For example, customer expenses logically vary over time based on the number of customers served and the cost of serving each customer. The unit cost of serving each customer, itself, depends on changes in the rate base and individual cost-of-service components, the extent and/or complexity of service provided to each customer, and the efficiency of the technology level employed in providing the service.

The long-run marginal cost approach generally projects total costs as the product of unit cost for the activity multiplied by the incidence of the activity. Unit costs are projected from cost-of-service components combined with time trends describing changes in level of service, complexity, or technology. The level of activity is projected in terms of variables external to the PTS (e.g., annual throughput) that are both logically and empirically related to the incurrence of costs. Implementation of the long-run marginal cost approach involves forecasting relationships developed through empirical studies of historical change in pipeline costs, accounting algorithms, exogenous assumptions, and inputs from other NEMS modules. These forecasting algorithms may be classified into three distinct areas, as follows:

- The projection of adjusted rate base and cost of capital for the combined existing and new capacity.
- The projection of components of the revenue requirements.
- The computation of variable and fixed rates for peak and off-peak periods.

The empirically derived forecasting algorithms discussed below are determined for each network arc.

Projection of Adjusted Rate Base and Cost of Capital

The approach for projecting adjusted rate base and cost of capital at the arc level is summarized in **Table 6-4**. Long-run marginal capital costs of pipeline companies reflect changes in the AA utility bond index rate. Once projected, the adjusted rate base is translated into capital-related components of the revenue requirements based on projections of the cost of capital, total operating and maintenance expenses, and algorithms for depreciation and tax effects.

The projected adjusted rate base for the combined existing and new pipelines at the arc level in year t is computed as the amount of gross plant in service in year t minus previous year's accumulated depreciation, depletion, and amortization plus total cash working capital minus accumulated deferred income taxes in year t.

$$APRB_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} + CWC_{a,t} - ADIT_{a,t} \quad (178)$$

where,

$APRB_{a,t}$ = adjusted rate base in dollars

$GPIS_{a,t}$ = total capital cost of plant in service (gross plant in service) in dollars

Table 6-4. Approach to Projection of Rate Base and Capital Costs

Projection Component	Approach
1. Adjusted Rate Base	
a. Gross plant in service in year t	
I. Capital cost of existing plant in service	Gross plant in service in the last historical year (2006)
II. Capacity expansion costs for new capacity	Accounting algorithm [equation 180]
b. Accumulated Depreciation, Depletion & Amortization	Accounting algorithm [equations 186, 187, 189] and empirically estimated for existing capacity [equation 188]
c. Cash and other working capital	User defined option for the combined existing and new capacity [equation 190]
d. Accumulated deferred income taxes	Empirically estimated for the combined existing and new capacity [equation 141]
f. Depreciation, depletion, and amortization	Existing Capacity: empirically estimated [equation 188] New Capacity: accounting algorithm [equation 189]
2. Cost of Capital	
a. Long-term debt rate	Projected AA utility bond yields adjusted by historical average deviation constant for long-term debt rate
b. Preferred equity rate	Projected AA utility bond yields adjusted by historical average deviation constant for preferred equity rate
c. Common equity return	Projected AA utility bond yields adjusted by historical average deviation constant for common equity return
3. Capital Structure	Held constant at average historical values

$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars

$CWC_{a,t}$ = total cash working capital including other cash working capital in dollars

$ADIT_{a,t}$ = accumulated deferred income taxes in dollars

a = arc

t = forecast year

All the variables in the above equation represent the aggregate variables for all interstate pipelines associated with an arc. The aggregate variables on the right hand side of the adjusted rate base equation are forecast by the equations below. First, total (existing and new) gross plant in service in the forecast year is determined as the sum of existing gross plant in service and new capacity expansion expenditures added to existing gross plant in service. New capacity expansion can be compression, looping, and new pipelines. For simplification, the replacement, refurbishment, retirement, and cost associated with new facilities for complying with Order 636 are not accounted for in projecting total gross plant in service in year t. Total gross plant in service for a network arc is forecast as follows:

$$GPIS_{a,t} = GPIS_E_{a,t} + GPIS_N_{a,t} \quad (179)$$

where,

$GPIS_{a,t}$ = total capital cost of plant in service (gross plant in service) in dollars
$GPIS_E_{a,t}$ = gross plant in service in the last historical year (2006)
$GPIS_N_{a,t}$ = capital cost of new plant in service in dollars
a = arc
t = forecast year

In the above equation, the capital cost of existing plant in service ($GPIS_E_{a,t}$) reflects the amount of gross plant in service in the last historical year (2006). The capital cost of new plant in service ($GPIS_N_{a,t}$) in year t is computed as the accumulated new capacity expansion expenditures from 2007 to year t and is determined by the following equation:

$$GPIS_N_{a,t} = \sum_{s=2004}^{t} NCAE_{a,s} \quad (180)$$

where,

$GPIS_N_{a,t}$ = gross plant in service for new capacity expansion in dollars
$NCAE_{a,s}$ = new capacity expansion expenditures occurring in year s after 2006 (in dollars) [equation 177]
s = the year new expansion occurred
a = arc
t = forecast year

Next, net plant in service in year t is determined as the difference between total capital cost of plant in service (gross plant in service) in year t and previous year's accumulated depreciation, depletion, and amortization.

$$NPIS_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} \quad (181)$$

where,

$NPIS_{a,t}$ = total net plant in service in dollars
$GPIS_{a,t}$ = total capital cost of plant in service (gross plant in service) in dollars
$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars
a = arc
t = forecast year

Accumulated depreciation, depletion, and amortization for the combined existing and new capacity in year t is determined by the following equation:

$$ADDA_{a,t} = ADDA_E_{a,t} + ADDA_N_{a,t} \quad (182)$$

where,

$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars
$ADDA_E_{a,t}$ = accumulated depreciation, depletion, and amortization for existing capacity in dollars
$ADDA_N_{a,t}$ = accumulated depreciation, depletion, and amortization for new capacity in dollars
a = arc
t = forecast year

With this and the relationship between the capital costs of existing and new plants in service from equation 179, total net plant in service ($NPIS_{a,t}$) is set equal to the sum of net plant in service for existing pipelines and new capacity expansions, as follows:

$$NPIS_{a,t} = NPIS_E_{a,t} + NPIS_N_{a,t} \quad (183)$$

$$NPIS_E_{a,t} = GPIS_E_{a,t} - ADDA_E_{a,t-1} \quad (184)$$

$$NPIS_N_{a,t} = GPIS_N_{a,t} - ADDA_N_{a,t-1} \quad (185)$$

where,

$NPIS_{a,t}$ = total net plant in service in dollars
$NPIS_E_{a,t}$ = net plant in service for existing capacity in dollars
$NPIS_N_{a,t}$ = net plant in service for new capacity in dollars
$GPIS_E_{a,t}$ = gross plant in service in the last historical year (2006)
$ADDA_E_{a,t}$ = accumulated depreciation, depletion, and amortization for existing capacity in dollars
$ADDA_N_{a,t}$ = accumulated depreciation, depletion, and amortization for new capacity in dollars
GPIS_N = gross plant in service for new capacity in dollars
a = arc
t = forecast year

Accumulated depreciation, depletion, and amortization for a network arc in year t is determined as the sum of previous year's accumulated depreciation, depletion, and amortization and current year's depreciation, depletion, and amortization.

$$ADDA_{a,t} = ADDA_{a,t-1} + DDA_{a,t} \quad (186)$$

where,

$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars
$DDA_{a,t}$ = annual depreciation, depletion, and amortization costs in dollars
a = arc
t = forecast year

Annual depreciation, depletion, and amortization for a network arc in year t equal the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with the arc.

$$DDA_{a,t} = DDA_E_{a,t} + DDA_N_{a,t} \quad (187)$$

where,

$DDA_{a,t}$ = annual depreciation, depletion, and amortization in dollars
$DDA_E_{a,t}$ = depreciation, depletion, and amortization costs for existing capacity in dollars
$DDA_N_{a,t}$ = depreciation, depletion, and amortization costs for new capacity in dollars
a = arc
t = forecast year

A regression equation is used to determine the annual depreciation, depletion, and amortization for existing capacity associated with an arc, while an accounting algorithm is used for new capacity. For existing capacity, this expense is forecast as follows:

$$DDA_E_{a,t} = \beta_{0,a} + \beta_1 * NPIS_E_{a,t-1} + \beta_2 * NEWCAP_E_{a,t} \quad (188)$$

where,

$DDA_E_{a,t}$ = annual depreciation, depletion, and amortization costs for existing capacity in nominal dollars
$\beta_{0,a}$ = DDA_C_a, constant term estimated by arc (Appendix F, Table F3.3, $\beta_{0,a} = B_ARC_{xx_yy}$)
β_1 = DDA_NPIS, estimated coefficient for net plant in service for existing capacity (Appendix F, Table F3.3)
β_2 = DDA_NEWCAP, estimated coefficient for the change in gross plant in service for existing capacity (Appendix F, Table F3.3)
$NPIS_E_{a,t}$ = net plant in service for existing capacity (dollars)
$NEWCAP_E_{a,t}$ = change in gross plant in service for existing capacity between t and t-1 (dollars)
a = arc
t = forecast year

The accounting algorithm used to define the annual depreciation, depletion, and amortization for new capacity assumes straight-line depreciation over a 30-year life, as follows:

$$DDA_N_{a,t} = GPIS_N_{a,t} / 30 \quad (189)$$

where,

$DDA_N_{a,t}$ = annual depreciation, depletion, and amortization for new capacity in dollars
$GPIS_N_{a,t}$ = gross plant in service for new capacity in dollars [equation 180]
30 = 30 years of plant life
a = arc
t = forecast year

Next, total cash working capital ($CWC_{a,t}$) for the combined existing and new capacity by arc in the adjusted rate base equation consists of cash working capital, material and supplies, and

other components that vary by company. Total cash working capital for pipeline transmission for existing and new capacity at the arc level is deflated using the chain weighted GDP price index with 2005 as a base. This level of cash working capital ($R_CWC_{a,t}$) is determined using a log-linear specification with correction for serial correlation given the economies in cash management in gas transmission. The estimated equation used for R_CWC (Appendix F, Table F3) is determined as a function of total operation and maintenance expenses, as defined below:

$$R_CWC_{a,t} = CWC_K * e^{(\beta_{0,a}*(1-\rho)+CWC_TOM*\log(R_TOM_{a,t})+\rho*\log(R_CWC_{a,t-1})-\rho*CWC_TOM*\log(R_TOM_{a,t-1}))} \quad (190)$$

where,

$R_CWC_{a,t}$ = total pipeline transmission cash working capital for existing and new capacity (2005 real dollars)

$\beta_{0,a}$ = CWC_C_a, estimated arc specific constant for gas transported from node to node (Appendix F, Table F3.2, $\beta_{0,a} = B_ARC_{xx_yy}$)

CWC_TOM = estimated R_TOM coefficient (Appendix F, Table F3.2)

$R_TOM_{a,t}$ = total operation and maintenance expenses in 2005 real dollars

CWC_K = correction factor estimated in stage 2 of the regression equation estimation process (Appendix F, Table F3)

ρ = autocorrelation coefficient from estimation (Appendix F, Table F3.2 -- CWC_RHO)

a = arc

t = forecast year

Last, the level of accumulated deferred income taxes for the combined existing and new capacity on a network arc in year t in the adjusted rate base equation depends on income tax regulations in effect, differences in tax and book depreciation, and the time vintage of past construction. The level of accumulated deferred income taxes for the combined existing and new capacity is derived as follows:

$$ADIT_{a,t} = \beta_{0,a} + \beta_1 * NEWCAP_{a,t} + \beta_2 * NEWCAP_{a,t} + \beta_3 * NEWCAP_{a,t} + ADIT_{a,t-1} \quad (191)$$

where,

$ADIT_{a,t}$ = accumulated deferred income taxes in dollars

$\beta_{0,a}$ = ADIT_Ca, constant term estimated by arc (Appendix F, Table F3.5, $\beta_{0,a} = B_ARC_{xx_yy}$)

β_1 = BNEWCAP_PRE2003, estimated coefficient on the change in gross plant in service in the pre-2003 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.

β_2 = BNEWCAP_2003_2004, estimated coefficient on the change in gross plant in service for the years 2003/2004 because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.

β_3 = BNEWCAP_POST2004, estimated coefficient on the change in gross plant in service in the post-2004 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.

$NEWCAP_{a,t}$ = change in gross plant in service for the combined existing and new capacity between years t and t-1 (in dollars)

a = arc

t = forecast year

Cost of capital. The capital-related components of the revenue requirement at the arc level depend upon the size of the adjusted rate base and the cost of capital to the pipeline companies associated with that arc. In turn, the company level costs of capital depend upon the rates of return on debt, preferred stock and common equity, and the amounts of debt and equity in the overall capitalization. Cost of capital for a company is the weighted average after-tax rate of return (WAROR) which is a function of long-term debt, preferred stock, and common equity. The rate of return variables for preferred stock, common equity, and debt are related to forecast macroeconomic variables. For the combined existing and new capacity at the arc level, it is assumed that these rates will vary as a function of the yield on AA utility bonds (provided by the Macroeconomic Activity Module as a percent) in year t adjusted by a historical average deviation constant, as follows:

$$PFER_{a,t} = MC_RMPUAANS_t / 100.0 + ADJ_PFER_a \quad (192)$$

$$CMER_{a,t} = MC_RMPUAANS_t / 100.0 + ADJ_CMER_a \quad (193)$$

$$LTDR_{a,t} = MC_RMPUAANS_t / 100.0 + ADJ_LTDR_a \quad (194)$$

where,

$PFER_{a,t}$ = rate of return for preferred stock

$CMER_{a,t}$ = common equity rate of return

$LTDR_{a,t}$ = long-term debt rate

$MC_RMPUAANS_t$ = AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPPUAA, percentage)

ADJ_PFER_a = historical average deviation constant (fraction) for rate of return for preferred stock (1994-2003, over 28 major gas pipeline companies) (D_PFER/100., Appendix E)

ADJ_CMER_a = historical average deviation constant (fraction) for rate of return for common equity (1994-2003, over 28 major gas pipeline companies) (D_CMER/100., Appendix E)

ADJ_LTDR_a = historical average deviation constant (fraction) for long term debt rate (1994-2003, over 28 major gas pipeline companies) (D_LTDR/100., Appendix E)

a = arc

t = forecast year

The weighted average cost of capital in the forecast year is computed as the sum of the capital-weighted rates of return for preferred stock, common equity, and debt, as follows:

$$WAROR_{a,t} = \frac{(PFER_{a,t} * PFES_{a,t}) + (CMER_{a,t} * CMES_{a,t}) + (LTDR_{a,t} * LTDS_{a,t})}{TOTCAP_{a,t}} \quad (195)$$

$$TOTCAP_{a,t} = (PFES_{a,t} + CMES_{a,t} + LTDS_{a,t}) \quad (196)$$

where,

$WAROR_{a,t}$ = weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$ = rate or return for preferred stock (fraction)
$PFES_{a,t}$ = value of preferred stock (dollars)
$CMER_{a,t}$ = common equity rate of return (fraction)
$CMES_{a,t}$ = value of common stock (dollars)
$LTDR_{a,t}$ = long-term debt rate (fraction)
$LTDS_{a,t}$ = value of long-term debt (dollars)
$TOTCAP_{a,t}$ = sum of the value of long-term debt, preferred stock, and common stock equity dollars)
a = arc
t = forecast year

The above equation can be written as a function of the rates of return and capital structure ratios as follows:

$$WAROR_{a,t} = (PFER_{a,t} * GPFESTR_{a,t}) + (CMER_{a,t} * GCMESTR_{a,t}) + (LTDR_{a,t} * GLTDSTR_{a,t}) \quad (197)$$

where,

$$GPFESTR_{a,t} = PFES_{a,t} / TOTCAP_{a,t} \quad (198)$$

$$GCMESTR_{a,t} = CMES_{a,t} / TOTCAP_{a,t} \quad (199)$$

$$GLTDSTR_{a,t} = LTDS_{a,t} / TOTCAP_{a,t} \quad (200)$$

and,

$WAROR_{a,t}$ = weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$ = coupon rate for preferred stock (fraction)
$CMER_{a,t}$ = common equity rate of return (fraction)
$LTDR_{a,t}$ = long-term debt rate (fraction)
$GPFESTR_a$ = ratio of preferred stock to estimated capital for existing and new capacity (fraction) [referred to as capital structure for preferred stock]
$GCMESTR_a$ = ratio of common stock to estimated capital for existing and new capacity (fraction)[referred to as capital structure for common stock]
$GLTDSTR_a$ = ratio of long term debt to estimated capital for existing and new capacity (fraction)[referred to as capital structure for long term debt]
$PFES_{a,t}$ = value of preferred stock (dollars)
$CMES_{a,t}$ = value of common stock (dollars)
$LTDS_{a,t}$ = value of long-term debt (dollars)

$TOTCAP_{a,t}$ = estimated capital equal to the sum of the value of preferred stock, common stock equity, and long-term debt (dollars)
a = arc
t = forecast year

In the financial database, the estimated capital for each interstate pipeline is by definition equal to its adjusted rate base. Hence, the estimated capital ($TOTCAP_{a,t}$) defined in equation 196 is equal to the adjusted rate base ($APRB_{a,t}$) defined in equation 178:

$$TOTCAP_{a,t} = APRB_{a,t} \quad (201)$$

where,

$TOTCAP_{a,t}$ = estimated capital in dollars
$APRB_{a,t}$ = adjusted rate base in dollars
a = arc
t = forecast year

Substituting the adjusted rate base variable $APRB_{a,t}$ for the estimated capital $TOTCAP_{a,t}$ in equations 198 to 200, the values of preferred stock, common stock, and long term debt by arc can be derived as functions of the capital structure ratios and the adjusted rate base. Capital structure is the percent of total capitalization (adjusted rate base) represented by each of the three capital components: preferred equity, common equity, and long-term debt. The percentages of total capitalization due to common stock, preferred stock, and long-term debt are considered fixed throughout the forecast. Assuming that the total capitalization fractions remain the same over the forecast horizon, the values of preferred stock, common stock, and long-term debt can be derived as follows:

$$\begin{aligned} PFES_{a,t} &= GPFESTR_a * APRB_{a,t} \\ CMES_{a,t} &= GCMESTR_a * APRB_{a,t} \\ LTDS_{a,t} &= GLTDSTR_a * APRB_{a,t} \end{aligned} \quad (202)$$

where,

$PFES_{a,t}$ = value of preferred stock in nominal dollars
$CMES_{a,t}$ = value of common equity in nominal dollars
$LTDS_{a,t}$ = long-term debt in nominal dollars
$GPFESTR_a$ = ratio of preferred stock to adjusted rate base for existing and new capacity (fraction) [referred to as capital structure for preferred stock]
$GCMESTR_a$ = ratio of common stock to adjusted rate base for existing and new capacity (fraction)[referred to as capital structure for common stock]
$GLTDSTR_a$ = ratio of long term debt to adjusted rate base for existing and new capacity (fraction)[referred to as capital structure for long term debt]
$APRB_{a,t}$ = adjusted pipeline rate base (dollars)
a = arc
t = forecast year

In the forecast year update phase, the capital structures ($GPFESTR_a$, $GCMESTR_a$, and $GLTDSTR_a$) at the arc level in the above equations are held constant over the forecast period. They are defined below as the average adjusted rate base weighted capital structures over all pipelines associated with an arc and over the historical time period (1997-2006).

$$GPFESTR_a = \frac{\sum_{t=1997}^{2006} \sum_{p} (GPFESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_{p} APRB_{a,p,t}} \quad (203)$$

$$GCMESTR_a = \frac{\sum_{t=1997}^{2006} \sum_{p} (GCMESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_{p} APRB_{a,p,t}} \quad (204)$$

$$GLTDSTR_a = \frac{\sum_{t=1997}^{2006} \sum_{p} (GLTDSTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_{p} APRB_{a,p,t}} \quad (205)$$

where,

$GPFESTR_a$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period

$GCMESTR_a$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period

$GLTDSTR_a$ = historical average capital structure for long term debt for existing and new capacity (fraction), held constant over the forecast period

$GPFESTR_{a,p,t}$ = capital structure for preferred stock (fraction) by pipeline company in the historical years (1997-2006) (Appendix E, D_PFES)

$GCMESTR_{a,p,t}$ = capital structure for common stock (fraction) by pipeline company in the historical years (1997-2006) (Appendix E, D_CMES)

$GLTDSTR_{a,p,t}$ = capital structure for long term debt (fraction) by pipeline company in the historical years (1997-2006) (Appendix E,D_LTDS)

$APRB_{a,p,t}$ = adjusted rate base (capitalization) by pipeline company in the historical years (1997-2006) (Appendix E, D_APRB)

p = pipeline company

a = arc

t = historical year

The weighted average cost of capital in the forecast year in equation 197 is forecast as follows:

$$WAROR_{a,t} = (PFER_{a,t} * GPFESTR_a) + (CMER_{a,t} * GCMESTR_a) + (LTDR_{a,t} * GLTDSTR_a) \quad (206)$$

where,

$WAROR_{a,t}$ = weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$ = coupon rate for preferred stock (fraction), function of AA utility bond rate [equation 192]
$CMER_{a,t}$ = common equity rate of return (fraction), function of AA utility bond rate [equation 193]
$LTDR_{a,t}$ = long-term debt rate (fraction), function of AA utility bond rate [equation 194]
$GPFESTR_a$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$GCMESTR_a$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$GLTDSTR_a$ = historical average capital structure for long term debt for existing and new capacity (fraction), held constant over the forecast period
a = arc
t = forecast year

The weighted-average after-tax rate of return on capital ($WAROR_{a,t}$) is applied to the adjusted rate base ($APRB_{a,t}$) to project the total return on rate base (after taxes), also known as the after-tax operating income, which is a major component of the revenue requirement.

Projection of Revenue Requirement Components

The approach to the projection of revenue requirement components is summarized in **Table 6-5**. Given the rate base, rates of return, and capitalization structure projections discussed above, the revenue requirement components are relatively straightforward to project. The capital-related components include total return on rate base (after taxes); Federal and State income taxes; deferred income taxes; other taxes; and depreciation, depletion, and amortization costs. Other components include total operating and maintenance expenses, and regulatory amortization, which is small and thus assumed to be negligible in the forecast period. The total operating and maintenance expense variable includes expenses for transmission of gas for others; administrative and general expenses; and sales, customer accounts and other expenses. The total cost of service (revenue requirement) at the arc level for a forecast year is determined as follows:

$$TCOS_{a,t} = TRRB_{a,t} + DDA_{a,t} + TOTAX_{a,t} + TOM_{a,t} \quad (207)$$

where,

Table 6-5. Approach to Projection of Revenue Requirements

Projection Component	Approach
1. Capital-Related Costs	
a. Total return on rate base	Direct calculation from projected rate base and rates of return
b. Federal/State income taxes	Accounting algorithms based on tax rates
c. Deferred income taxes	Difference in the accumulated deferred income taxes between years t and t-1
2. Depreciation, Depletion, and Amortization	Estimated equation and accounting algorithm
3. Total Operating and Maintenance Expenses	Estimated equation
4. Other Taxes	Previous year's other taxes adjusted to inflation rate and growth in capacity

$TCOS_{a,t}$ = total cost-of-service or revenue requirement for existing and new capacity (dollars)
$TRRB_{a,t}$ = total return on rate base for existing and new capacity after taxes (dollars)
$DDA_{a,t}$ = depreciation, depletion, and amortization for existing and new capacity (dollars)
$TOTAX_{a,t}$ = total Federal and State income tax liability for existing and new capacity (dollars)
$TOM_{a,t}$ = total operating and maintenance expenses for existing and new capacity (dollars)
a = arc
t = forecast year

The total return on rate base for existing and new capacity is computed from the projected weighted cost of capital and estimated rate base, as follows:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \quad (208)$$

where,

$TRRB_{a,t}$ = total return on rate base (after taxes) for existing and new capacity in dollars
$WAROR_{a,t}$ = weighted-average after-tax rate of return on capital for existing and new capacity (fraction)
$APRB_{a,t}$ = adjusted pipeline rate base for existing and new capacity in dollars
a = arc
t = forecast year

The return on rate base for existing and new capacity on an arc can be broken out into the three components:

$$PFEN_{a,t} = GPFESTR_a * PFER_{a,t} * APRB_{a,t} \quad (209)$$

$$CMEN_{a,t} = GCMESTR_a * CMER_{a,t} * APRB_{a,t} \quad (210)$$

$$LTDN_{a,t} = GLTDSTR_a * LTDR_{a,t} * APRB_{a,t} \quad (211)$$

where,

$PFEN_{a,t}$ = total return on preferred stock for existing and new capacity (dollars)

$GPFESTR_a$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period

$PFER_{a,t}$ = coupon rate for preferred stock for existing and new capacity (fraction)

$APRB_{a,t}$ = adjusted rate base for existing and new capacity (dollars)

$CMEN_{a,t}$ = total return on common stock equity for existing and new capacity (dollars)

$GCMESTR_a$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period

$CMER_{a,t}$ = common equity rate of return for existing and new capacity (fraction)

$LTDN_{a,t}$ = total return on long-term debt for existing and new capacity (dollars)

$GLTDSTR_a$ = historical average capital structure ratio for long term debt for existing and new capacity (fraction), held constant over the forecast period

$LTDR_{a,t}$ = long-term debt rate for existing and new capacity (fraction)

a = arc

t = forecast year

Next, annual depreciation, depletion, and amortization $DDA_{a,t}$ for a network arc in year t is calculated as the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with the arc. $DDA_{a,t}$ is defined earlier in equation 187.

Next, total taxes consist of Federal income taxes, State income taxes, deferred income taxes, and other taxes. Federal income taxes and State income taxes are calculated using average tax rates. The equation for total taxes is as follows:

$$TOTAX_{a,t} = FSIT_{a,t} + DIT_{a,t} + OTTAX_{a,t} \quad (212)$$

$$FSIT_{a,t} = FIT_{a,t} + SIT_{a,t} \quad (213)$$

where,

$TOTAX_{a,t}$ = total Federal and State income tax liability for existing and new capacity (dollars)

$FSIT_{a,t}$ = Federal and State income tax for existing and new capacity (dollars)

$FIT_{a,t}$ = Federal income tax for existing and new capacity (dollars)

$SIT_{a,t}$ = State income tax for existing and new capacity (dollars)
$DIT_{a,t}$ = deferred income taxes for existing and new capacity (dollars)
$OTTAX_{a,t}$ = all other Federal, State, or local taxes for existing and new capacity (dollars)
a = arc
t = forecast year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the Federal tax rate. The after-tax profit is determined as follows:

$$ATP_{a,t} = APRB_{a,t} * (PFER_{a,t} * GPFESTR_a + CMER_{a,t} * GCMESTR_a) \quad (214)$$

where,

$ATP_{a,t}$ = after-tax profit for existing and new capacity (dollars)
$APRB_{a,t}$ = adjusted pipeline rate base for existing and new capacity (dollars)
$PFER_{a,t}$ = coupon rate for preferred stock for existing and new capacity (fraction)
$GPFESTR_a$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$CMER_{a,t}$ = common equity rate of return for existing and new capacity (fraction)
$GCMESTR_a$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
a = arc
t = forecast year

and the Federal income taxes are:

$$FIT_{a,t} = (FRATE * ATP_{a,t} / 1. - FRATE) \quad (215)$$

where,

$FIT_{a,t}$ = Federal income tax for existing and new capacity (dollars)
FRATE = Federal income tax rate (fraction, Appendix E)
$ATP_{a,t}$ = after-tax profit for existing and new capacity (dollars)
a = arc
t = forecast year

State income taxes are computed by multiplying the sum of taxable profit and the associated Federal income tax by a weighted-average State tax rate associated with each pipeline company. The weighted-average State tax rate is based on peak service volumes in each State served by the pipeline company. State income taxes are computed as follows:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \quad (216)$$

where,

$SIT_{a,t}$ = State income tax for existing and new capacity (dollars)
SRATE = average State income tax rate (fraction, Appendix E)
$FIT_{a,t}$ = Federal income tax for existing and new capacity (dollars)
$ATP_{a,t}$ = after-tax profits for existing and new capacity (dollars)
a = arc
t = forecast year

Deferred income taxes for existing and new capacity at the arc level are the differences in the accumulated deferred income taxes between year t and year t-1.

$$DIT_{a,t} = ADIT_{a,t} - ADIT_{a,t-1} \quad (217)$$

where,

$DIT_{a,t}$ = deferred income taxes for existing and new capacity (dollars)
$ADIT_{a,t}$ = accumulated deferred income taxes for existing and new capacity (dollars)
a = arc
t = forecast year

Other taxes consist of a combination of ad valorem taxes (which grow with company revenue), property taxes (which grow in proportion to gross plant), and all other taxes (assumed constant in real terms). Other taxes in year t are determined as the previous year's other taxes adjusted for inflation and capacity expansion.

$$OTTAX_{a,t} = OTTAX_{a,t-1} * EXPFAC_{a,t} * (MC_PCWGDP_t / MC_PCWGDP_{t-1}) \quad (218)$$

where,

$OTTAX_{a,t}$ = all other taxes assessed by Federal, State, or local governments except income taxes for existing and new capacity (dollars)
$EXPFAC_{a,t}$ = capacity expansion factor (see below)
MC_PCWGDPt = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = forecast year

The capacity expansion factor is expressed as follows:

$$EXPFAC_{a,t} = PTCURPCAP_{a,t} / PTCURPCAP_{a,t-1} \quad (219)$$

where,

$EXPFAC_{a,t}$ = capacity expansion factor (growth in capacity)
$PTCURPCAP_{a,t}$ = current pipeline capacity (Bcf) for existing and new capacity
a = arc
t = forecast year

Last, the total operating and maintenance costs for existing and new capacity by arc ($R_TOM_{a,t}$) are determined using a log-linear form, given the economies of scale inherent in gas transmission. The estimated equation used for R_TOM (Appendix F, Table F3) is

determined as a function of gross plant in service, $GPIS_a$, a level of accumulated depreciation relative to gross plant in service, $DEPSHR_a$, and a time trend, TECHYEAR, that proxies the state of technology, as defined below:

$$R_TOM_{a,t} = TOM_K * e^{(\beta_{0,a} * (1-\rho) + G2 + G3 + G4 + G5 + G6 - \rho * (G7 + G8 + G4 + G9))} \quad (220)$$

where,

$R_TOM_{a,t}$ = total operating and maintenance cost for existing and new capacity (2005 real dollars)

TOM_K = correction factor estimated in stage 2 of the regression equation estimation process (Appendix F, Table F3)

$\beta_{0,a}$ = TOM_C, constant term estimated by arc (Appendix F, Table F3.6, $\beta_{0,a} = B_ARC_{xx_yy}$)

G_2 = $\beta_1 * \log(GPIS_{a,t-1})$

G_3 = $\beta_2 * DEPSHR_{a,t-1}$

G_4 = $\beta_3 * 2006.0$

G_5 = $\beta_4 * (TECHYEAR - 2006.0)$

G_6 = $\rho * \log(R_TOM_{a,t-1})$

G_7 = $\beta_1 * \log(GPIS_{a,t-2})$

G_8 = $\beta_2 * DEPSHR_{a,t-2}$

G_9 = $\beta_4 * (TECHYEAR - 1.0 - 2006.0)$

log = natural logarithm operator

ρ = estimated autocorrelation coefficient (Appendix F, Table F3.6 -- TOM_RHO)

β_1 = TOM_GPIS_1, estimated coefficient on the change in gross plant in service (Appendix F, Table F3.6)

β_2 = TOM_DEPSHR, estimated coefficient for the accumulated depreciation of the plant relative to the GPIS (Appendix F, Table F3.6)

β_3 = TOM_BYEAR, estimated coefficient for the time trend variable TECHYEAR (Appendix F, Table F3.6)

β_4 = TOM_BYEAR_EIA = TOM_BYEAR, estimated future rate of decline in R_TOM due to technology improvements and efficiency gains. EIA assumes that this coefficient is the same as the coefficient for the time trend variable TECHYEAR (Appendix F, Table F3.6)

$DEPSHR_{a,t}$ = level of the accumulated depreciation of the plant relative to the gross plant in service for existing and new capacity at the beginning of year t. This variable is a proxy for the age of the capital stock.

$GPIS_{a,t}$ = capital cost of plant in service for existing and new capacity in dollars (not deflated)

TECHYEAR = MODYEAR (time trend in 4 digit Julian units, the minimum value of this variable in the sample being 1997, otherwise TECHYEAR=0 if less than 1997)

a = arc

t = forecast year

For consistency the total operating and maintenance costs are converted to nominal dollars:

$$TOM_{a,t} = R_TOM_{a,t} * \frac{MC_PCWGDP_t}{MC_PCWGDP_{2000}} \quad (221)$$

where,

$TOM_{a,t}$ = total operating and maintenance costs for existing and new capacity (nominal dollars)
$R_TOM_{a,t}$ = total operating and maintenance costs for existing and new capacity (2005 real dollars)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = forecast year

Once all four components ($TRRB_{a,t}$, $DDA_{a,t}$, $TOTAX_{a,t}$, $TOM_{a,t}$) of the cost-of-service $TCOST_{a,t}$ of equation 207 are computed by arc in year t, each of them will be disaggregated into fixed and variable costs which in turn will be disaggregated further into reservation and usage costs using the allocation factors for a straight fixed variable (SFV) rate design summarized in **Table 6-6**.[89] Note that the return on rate base ($TRRB_{a,t}$) has three components ($PFEN_{a,t}$, $CMEN_{a,t}$, and $LTDN_{a,t}$ [equations 209, 210, and 211]).

Disaggregation of Cost-of-Service Components into Fixed and Variable Costs

Let $Item_{i,a,t}$ be a cost-of-service component (i=cost component index, a=arc, and t=forecast year). Using the first group of rate design allocation factors ξi (**Table 6-6**), all the components of cost-of-service computed in the above section can be split into fixed and variable costs, and then summed over the cost categories to determine fixed and variable costs-of-service as follows:

$$FC_{a,t} = \sum_i (\xi_i * Item_{i,a,t}) \quad (222)$$

$$VC_{a,t} = \sum_i [(1.0 - \xi_i) * Item_{i,a,t}] \quad (223)$$

$$TCOS_{a,t} = FC_{a,t} + VC_{a,t} \quad (224)$$

where,

$TCOS_{a,t}$ = total cost-of-service for existing and new capacity (dollars)
$FC_{a,t}$ = fixed cost for existing and new capacity (dollars)
$VC_{a,t}$ = variable cost for existing and new capacity (dollars)
$Item_{i,a,t}$ = cost-of-service component index at the arc level
ξ_i = first group of allocation factors (ratios) to disaggregate the cost-of-service components into fixed and variable costs

[89] The allocation factors of SFV rate design are given in percent in this table for illustration purposes. They are converted into ratios immediately after they are read in from the input file by dividing by 100.

Table 6-6. Percentage Allocation Factors for a Straight Fixed Variable (SFV) Rate Design

Cost-of-service Items (percentage) [$Item_{i,a,t}$, i=cost component index, a=arc, t=year]	**Break up cost-of-service items into fixed and variable costs**		**Break up fixed cost items into reservation and usage costs**		**Break up variable cost items into reservation and usage costs**	
$Item_{i,a,t}$	**$FC_{i,a,t}$**	**$VC_{i,a,t}$**	**$RFC_{i,a,t}$**	**$UFC_{i,a,t}$**	**$RVC_{i,a,t}$**	**$UVC_{i,a,t}$**
Cost Allocation Factors	**ξ_i**	**100 - ξ_i**	**λ_i**	**100 - λ_i**	**μ_i**	**100-μ_i**
After-tax Operating Income						
Return on Preferred Stocks	100	0	100	0	0	100
Return on Common Stocks	100	0	100	0	0	100
Return on Long-Term Debt	100	0	100	0	0	100
Normal Operating Expenses						
Depreciation	100	0	100	0	0	100
Income Taxes	100	0	100	0	0	100
Deferred Income Taxes	100	0	100	0	0	100
Other Taxes	100	0	100	0	0	100
Total O&M	60	40	100	0	0	100

ξ_i = first group of allocation factors (ratios) to disaggregate the cost-of-service components into fixed and variable costs
i = subscript to designate a cost-of-service component (i=1 for PFEN, i=2 for CMEN, i=3 for LTDN, i=4 for DDA, i=5 for FSIT, i=6 for DIT, i=7 for OTTAX, and i=8 for TOM)
a = arc
t = forecast year

Disaggregation of Fixed and Variable Costs into Reservation and Usage Costs

Each type of cost-of-service component (fixed or variable) in the above equations can be further disaggregated into reservation and usage costs using the second and third groups of rate design allocation factors λi and μi (**Table 6-6**), as follows:

$$RFC_{a,t} = \sum_i (\lambda_i * \xi_i * Item_{i,a,t}) \quad (225)$$

$$UFC_{a,t} = \sum_i [(1.0 - \lambda_i) * \xi_i * Item_{i,a,t}] \quad (226)$$

$$RVC_{a,t} = \sum_i [\mu_i * (1.0 - \xi_i) * Item_{i,a,t}] \quad (227)$$

$$UVC_{a,t} = \sum_i [(1.0 - \mu_i) * (1.0 - \xi_i) * Item_{i,a,t}] \quad (228)$$

$$TCOS_{a,t} = RFC_{a,t} + UFC_{a,t} + RVC_{a,t} + UVC_{a,t} \quad (229)$$

where,

TCOSa,t = total cost-of-service for existing and new capacity (dollars)
RFCa,t = fixed reservation cost for existing and new capacity (dollars)
UFCa,t = fixed usage cost for existing and new capacity (dollars)
RVCa,t = variable reservation cost for existing and new capacity (dollars)
UVCa,t = variable usage cost for existing and new capacity (dollars)
Itemi,a,t = cost-of-service component index at the arc level
ξi = first group of allocation factors to disaggregate cost-of-service components into fixed and variable costs
λi = second group of allocation factors to disaggregate fixed costs into reservation and usage costs
μi = third group of allocation factors to disaggregate variable costs into reservation and usage costs
i = subscript to designate a cost-of-service component (i=1 for PFEN, i=2 for CMEN, i=3 for LTDN, i=4 for DDA, i=5 for FSIT, i=6 for DIT, i=7 for OTTAX, and i=8 for TOM)
a = arc
t = forecast year

The summation of fixed and variable reservation costs (RFC and RVC) yields the total reservation cost (RCOST). This can be disaggregated further into peak and off-peak reservation costs, which are used to develop variable tariffs for peak and off-peak time periods. The summation of fixed and variable usage costs (UFC and UVC), which yields the total usage cost (UCOST), is used to compute the annual average fixed usage fees. Both types of rates are developed in the next section. The equations for the reservation and usage costs can be expressed as follows:

$$RCOST_{a,t} = (RFC_{a,t} + RVC_{a,t}) \quad (230)$$

$$UCOST_{a,t} = (UFC_{a,t} + UVC_{a,t}) \quad (231)$$

where,

$RCOST_{a,t}$ = reservation cost for existing and new capacity (dollars)
$UCOST_{a,t}$ = annual usage cost for existing and new capacity (dollars)
$RFC_{a,t}$ = fixed reservation cost for existing and new capacity (dollars)
$UFC_{a,t}$ = fixed usage cost for existing and new capacity (dollars)
$RVC_{a,t}$ = variable reservation cost for existing and new capacity (dollars)
$UVC_{a,t}$ = variable usage cost for existing and new capacity (dollars)
a = arc
t = forecast period

As **Table 6-6** indicates, all the fixed costs are included in the reservation costs and all the variable costs are included in the usage costs.

Computation of Rates for Forecast Years

The reservation and usage costs-of-service RCOST and UCOST determined above are used separately to develop two types of rates at the arc level: variable tariffs and annual fixed usage fees. The determination of both rates is described below.

Variable Tariff Curves

Variable tariffs are proportional to reservation charges and are broken up into peak and off-peak time periods. Variable tariffs are derived directly from variable tariff curves which are developed based on reservation costs, utilization rates, annual flows, and other curve parameters.

In the PTS code, these variable curves are defined by a FUNCTION (NGPIPE_VARTAR) which is called by the ITS to compute the variable tariffs for peak and off-peak by arc and by forecast year. In this pipeline function, the tariff curves are segmented such that tariffs associated with *current capacity* and *capacity expansion* are represented by separate but similar equations. A uniform functional form is used to define these tariff curves for both the *current capacity* and *capacity expansion segments* of the tariff curves. It is defined as a function of a base point [price and quantity (PNOD, QNOD)] using different *process-specific* parameters, peak or off-peak flow, and a price elasticity. This functional form is presented below:

current capacity segment:

$$NGPIPE_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA_PIPE} \quad (232)$$

capacity expansion segment:

$$NGPIPE_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA2_PIPE} \quad (233)$$

such that,

for peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * PKSHR_YR}{(QNOD_{a,t} * MC_PCWGDP_t)} \quad (234)$$

$$QNOD_{a,t} = PT\ NETFLOW_{a,t} \quad (235)$$

for off-peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR_YR)}{(QNOD_{a,t} * MC_PCWGDP_t)} \quad (236)$$

$$QNOD_{a,t} = PT\,NETFLOW_{a,t} \quad (237)$$

where,

$NGPIPE_VARTAR_{a,t}$ = function to define pipeline tariffs (87$/Mcf)
$PNOD_{a,t}$ = base point, price (87$/Mcf)
$QNOD_{a,t}$ = base point, quantity (Bcf)
$Q_{a,t}$ = flow along pipeline arc (Bcf)
ALPHA_PIPE = price elasticity for pipeline tariff curve for current capacity (Appendix E)
ALPHA2_PIPE = price elasticity for pipeline tariff curve for capacity expansion segment (Appendix E)
$RCOST_{a,t}$ = reservation cost-of-service (million dollars)
$PTNETFLOW_{a,t}$ = natural gas network flow (throughput, Bcf)
PKSHR_YR = portion of the year represented by the peak season (fraction)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = forecast year

Annual Fixed Usage Fees

The annual fixed usage fees (volumetric charges) are derived directly from the usage costs, peak and off-peak utilization rates, and annual arc capacity. These fees are computed as the average fees over each forecast year, as follows:

$$FIXTAR_{a,t} = UCOST_{a,t} / [(PKSHR_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + (1.0 - PKSHR_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC_PCWGDP_t] \quad (238)$$

where,

$FIXTAR_{a,t}$ = annual fixed usage fees for existing and new capacity (87$/Mcf)
$UCOST_{a,t}$ = annual usage cost for existing and new capacity (million dollars)
PKSHR_YR = portion of the year represented by the peak season (fraction)
$PTPKUTZ_{a,t}$ = peak pipeline utilization (fraction)
$PTCURPCAP_{a,t}$ = current pipeline capacity (Bcf)
$PTOPUTZ_{a,t}$ = off-peak pipeline utilization (fraction)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = forecast year

As can be seen from the allocation factors in **Table 6-6**, usage costs (UCOST) are less than 10 percent of reservation costs (RCOST). Therefore, annual fixed usage fees which are proportional to usage costs are expected to be less than 10 percent of the variable tariffs. In general, these fixed fees are within the range of 5 percent of the variable tariffs which are charged to firm customers.

Canadian Fixed and Variable Tariffs

Fixed and variables tariffs along Canadian import arcs are defined using input data. Fixed tariffs are obtained directly from the data (Appendix E, $ARC_FIXTAR_{n,a,t}$), while variables tariffs are calculated in the FUNCTION subroutine (NGPIPE_VARTAR) and are based on pipeline utilization and a maximum expected tariff, CNMAXTAR. If the pipeline utilization along a Canadian arc for any time period (peak or off-peak) is less than 50 percent, then the pipeline tariff is set to a low level (70 percent of CNMAXTAR). If the Canadian pipeline utilization is between 50 and 90 percent, then the pipeline tariff is set to a level between 70 and 80 percent of CNMAXTAR. The sliding scale is determined using the corresponding utilization factor, as follows:

$$NGPIPE_VARTAR_{a,t} = CNMAXTAR - [CNMAXTAR * (1.0 - 0.9) * 2.0] - [CNMAXTAR * (0.9 - CANUTIL_{a,t}) * 0.25] \quad (239)$$

If the Canadian pipeline utilization is greater than 90 percent, then the pipeline tariff is set to between 80 and 100 percent of CNMAXTAR. This is accomplished again using Canadian pipeline utilization, as follows:

$$NGPIPE_VARTAR_{a,t} = CNMAXTAR - [CNMAXTAR * (1.0 - CANUTIL_{a,t}) * 2.0] \quad (240)$$

where,

$$CANUTIL_{a,t} = \frac{Q_{a,t}}{QNOD_{a,t}} \quad (241)$$

for peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * PKSHR_YR * PTPKUTZ_{a,t} \quad (242)$$

for off-peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * (1.0 - PKSHR_YR) * PTOPUTZ_{a,t} \quad (243)$$

and,

$NGPIPE_VARTAR_{a,t}$ = function to define pipeline tariffs (87$/Mcf)
CNMAXTAR = maximum effective tariff (87$/Mcf, ARC_VARTAR, Appendix E)

$CANUTIL_{a,t}$ = pipeline utilization (fraction)
$QNOD_{a,t}$ = base point, quantity (Bcf)
$Q_{a,t}$ = flow along pipeline arc (Bcf)
PKSHR_YR = portion of the year represented by the peak season (fraction)
$PTPKUTZ_{a,t}$ = peak pipeline utilization (fraction)
$PTCURPCAP_{a,t}$ = current pipeline capacity (Bcf)
$PTOPUTZ_{a,t}$ = off-peak pipeline utilization (fraction)
a = arc
t = forecast year

For the eastern and western Canadian storage regions, the "variable" tariff is set to zero and only the assumed "fixed" tariff (Appendix E, ARC_FIXTAR) is applied.

Storage Tariff Routine Methodology

Background

This section describes the methodology used to assign a storage tariff for each of the 12 NGTDM regions. All variables and equations presented below are used for the forecast time period (1999-2030). If the time period t is less than 1999, the associated variables are set to the initial values read in from the input file (Foster's storage financial database[90] by region and year, 1990-1998).

This section starts with the presentation of the natural gas storage cost-of-service equation by region. The equation sums four components to be forecast: after-tax[91] total return on rate base (operating income); total taxes; depreciation, depletion, and amortization; and total operating and maintenance expenses. Once these four components are computed, the regional storage cost of service is projected and, with the associated effective storage capacity provided by the ITS, a storage tariff curve can be established (as described at the end of this section).

Cost-of-Service by Storage Region

The cost-of-service (or revenue requirement) for existing and new storage capacity in an NGTDM region can be written as follows:

$$STCOS_{r,t} = STBTOI_{r,t} + STDDA_{r,t} + STTOTAX_{r,t} + STTOM_{r,t} \quad (244)$$

where,

$STCOS_{r,t}$ = total cost-of-service or revenue requirement for existing and new capacity (dollars)

[90] Natural Gas Storage Financial Data, compiled by Foster Associates, Inc., Bethesda, Maryland for EIA under purchase order #01-99EI36663 in December of 1999. This data set includes financial information on 33 major storage companies. The primary source of the data is FERC Form 2 (or Form 2A for the smaller pipelines). These data can be purchased from Foster Associates.

[91] 'After-tax' in this section refers to 'after taxes have been taken out.'

$STBTOI_{r,t}$ = total return on rate base for existing and new capacity (after-tax operating income) (dollars)
$STDDA_{r,t}$ = depreciation, depletion, and amortization for existing and new capacity (dollars)
$STTOTAX_{r,t}$ = total Federal and State income tax liability for existing and new capacity (dollars)
$STTOM_{r,t}$ = total operating and maintenance expenses for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

The storage cost-of-service by region is first computed in nominal dollars and subsequently converted to 1987$ for use in the computation of a base for regional storage tariff, PNOD (87$/Mcf). PNOD is used in the development of a regional storage tariff curve. An approach is developed to project the storage cost-of-service in nominal dollars by NGTDM region in year t and is provided in **Table 6-7**.

Table 6-7. Approach to Projection of Storage Cost-of-Service

Projection Component	Approach
1. Capital-Related Costs	
a. Total return in rate base	Direct calculation from projected rate base and rates of return
b. Federal/State income taxes	Accounting algorithms based on tax rates
c. Deferred income taxes	Difference in the accumulated deferred income taxes between years t and t-1
2. Depreciation, Depletion, and Amortization	Estimated equation and accounting algorithm
3. Total Operating and Maintenance Expenses	Estimated equation

Computation of total return on rate base (after-tax operating income), STBTOIr,t

The total return on rate base for existing and new capacity is computed from the projected weighted cost of capital and estimated rate base, as follows:

$$STBTOI_{r,t} = STWAROR_{r,t} * STAPRB_{r,t} \quad (245)$$

where,

$STBTOI_{r,t}$ = total return on rate base (after-tax operating income) for existing and new capacity in dollars
$STWAROR_{r,t}$ = weighted-average after-tax rate of return on capital for existing and new capacity (fraction)
$STAPRB_{r,t}$ = adjusted storage rate base for existing and new capacity in dollars
r = NGTDM region
t = forecast year

The return on rate base for existing and new storage capacity in an NGTDM region can be

broken out into three components as shown below.

$$STPFEN_{r,t} = STGPFESTR_r * STPFER_{r,t} * STAPRB_{r,t} \quad (246)$$

$$STCMEN_{r,t} = STGCMESTR_r * STCMER_{r,t} * STAPRB_{r,t} \quad (247)$$

$$STLTDN_{r,t} = STGLTDSTR_r * STLTDR_{r,t} * STAPRB_{r,t} \quad (248)$$

where,

$STPFEN_{r,t}$ = total return on preferred stock for existing and new capacity (dollars)
$STPFER_{r,t}$ = coupon rate for preferred stock for existing and new capacity (fraction)
$STGPFESTR_r$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$STAPRB_{r,t}$ = adjusted rate base for existing and new capacity (dollars)
$STCMEN_{r,t}$ = total return on common stock equity for existing and new capacity (dollars)
$STGCMESTR_r$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$STCMER_{r,t}$ = common equity rate of return for existing and new capacity (fraction)
$STLTDN_{r,t}$ = total return on long-term debt for existing and new capacity (dollars)
$STGLTDSTR_r$ = historical average capital structure ratio for long term debt for existing and new capacity (fraction), held constant over the forecast period
$STLTDR_{r,t}$ = long-term debt rate for existing and new capacity (fraction)
r = NGTDM region
t = forecast year

Note that the total return on rate base is the sum of the above equations and can be expressed as:

$$STBTOI_{r,t} = (STPFEN_{r,t} + STCMEN_{r,t} + STLTDN_{r,t}) \quad (249)$$

It can be seen from the above equations that the weighted average rate of return on capital for existing and new storage capacity, $STWAROR_{r,t}$, can be determined as follows:

$$STWAROR_{r,t} = STPFER_{r,t} * STGPFESTR_r + STCMER_{r,t} * STGCMESTR_r + STLTDR_{r,t} * STGLTDSTR_r \quad (250)$$

The historical average capital structure ratios $STGPFESTR_r$, $STGCMESTR_r$, and $STGLTDSTR_r$ in the above equation are computed as follows:

$$STGPFESTR_r = \frac{\sum_{t=1990}^{1998} STPFES_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \quad (251)$$

$$STGCMESTR_r = \frac{\sum_{t=1990}^{1998} STCMES_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \quad (252)$$

$$STGLTDSTR_r = \frac{\sum_{t=1990}^{1998} STLTDS_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \quad (253)$$

where,

$STGPFESTR_r$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period

$STGCMESTR_r$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period

$STGLTDSTR_r$ = historical average capital structure ratio for long term debt for existing and new capacity (fraction), held constant over the forecast period

$STPFES_{r,t}$ = value of preferred stock for existing capacity (dollars) [read in as D_PFES]

$STCMES_{r,t}$ = value of common stock equity for existing capacity (dollars) [read in as D_CMES]

$STLTDS_{r,t}$ = value of long-term debt for existing capacity (dollars) [read in as D_LTDS]

$STAPRB_{r,t}$ = adjusted rate base for existing capacity (dollars) [read in as D_APRB]

r = NGTDM region

t = forecast year

In the STWAROR equation, the rate of return variables for preferred stock, common equity, and debt ($STPFER_{r,t}$, $STCMER_{r,t}$, and $STLTDR_{r,t}$) are related to forecast macroeconomic variables. These rates of return can be determined as a function of nominal AA utility bond index rate (provided by the Macroeconomic Module) and a regional historical average constant deviation as follows:

$$STPFER_{r,t} = MC_RMPUAANS_t / 100.0 + ADJ_STPFER_r \quad (254)$$

$$STCMER_{r,t} = MC_RMPUAANS_t / 100.0 + ADJ_STCMER_r \quad (255)$$

$$STLTDR_{r,t} = MC_RMPUAANS_t / 100.0 + ADJ_STLTDR_r \quad (256)$$

where,

$STPFER_{r,t}$ = rate of return for preferred stock

$STCMER_{r,t}$ = common equity rate of return

$STLTDR_{r,t}$ = long-term debt rate

$MC_RMPUAANS_t$ = AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPUAA, percentage)

ADJ_STPFER_r = historical weighted average deviation constant (fraction) for preferred stock rate of return (1990-1998)

ADJ_STCMER_r = historical weighted average deviation constant (fraction) for common equity rate of return (1990-1998)

ADJ_STLTDR_r = historical weighted average deviation constant (fraction) for long term debt rate (1990-1998)

r = NGTDM region

t = forecast year

The historical weighted average deviation constants by NGTDM region are computed as follows:

$$ADJ_STLTDR_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STLTDN_{r,t}}{STLTDS_{r,t}} - MC_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \quad (257)$$

$$ADJ_STPFER_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STPFEN_{r,t}}{STPFES_{r,t}} - MC_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \quad (258)$$

$$ADJ_STCMER_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STCMEN_{r,t}}{STCMES_{r,t}} - MC_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \quad (259)$$

where,

ADJ_STLTDR_r = historical weighted average deviation constant (fraction) for long term debt rate

ADJ_STCMER_r = historical weighted average deviation constant (fraction) for common equity rate of return

ADJ_STPFER_r = historical weighted average deviation constant (fraction) for preferred stock rate of return

$STPFEN_{r,t}$ = total return on preferred stock for existing capacity (dollars) [read in as D_PFEN]
$STCMEN_{r,t}$ = total return on common stock equity for existing capacity (dollars) [read in as D_CMEN]
$STLTDN_{r,t}$ = total return on long-term debt for existing capacity (dollars) [read in as D_LTDN]
$STPFES_{r,t}$ = value of preferred stock for existing capacity (dollars) [read in as D_PFES]
$STCMES_{r}$ = value of common stock equity for existing capacity (dollars) [read in as D_CMES]
$STLTDS_{r}$ = value of long-term debt for existing capacity (dollars) [read in as D_LTDS]
$MC_RMPUAANS_{t}$ = AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPPUAA, percentage)
$STGPIS_{r,t}$ = original capital cost of plant in service (dollars) [read in as D_GPIS]
r = NGTDM region
t = forecast year

Computation of adjusted rate base, $STAPRB_{r,t}$[92]

The adjusted rate base for existing and new storage facilities in an NGTDM region has three components and can be written as follows:

$$STAPRB_{r,t} = STNPIS_{r,t} + STCWC_{r,t} - STADIT_{r,t} \quad (260)$$

where,

$STAPRB_{r,t}$ = adjusted storage rate base for existing and new capacity (dollars)
$STNPIS_{r,t}$ = net plant in service for existing and new capacity (dollars)
$STCWC_{r,t}$ = total cash working capital for existing and new capacity (dollars)
$STADIT_{r,t}$ = accumulated deferred income taxes for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

The net plant in service is the level of gross plant in service minus the accumulated depreciation, depletion, and amortization. It is given by the following equation:

$$STNPIS_{r,t} = STGPIS_{r,t} - STADDA_{r,t-1} \quad (261)$$

[92]In this section, any variable ending with "_E" will signify that the variable is for the existing storage capacity as of the end of 1998, and any variable ending with "_N" will mean that the variable is for the new storage capacity added from 1999 to 2025.

where,

$STNPIS_{r,t}$ = net plant in service for existing and new capacity (dollars)
$STGPIS_{r,t}$ = gross plant in service for existing and new capacity (dollars)
$STADDA_{r,t}$ = accumulated depreciation, depletion, and amortization for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

The gross and net plant-in-service variables can be written as the sum of their respective existing and new gross and net plants in service as follows:

$$STGPIS_{r,t} = STGPIS_E_{r,t} + STGPIS_N_{r,t} \quad (262)$$

$$STNPIS_{r,t} = STNPIS_E_{r,t} + STNPIS_N_{r,t} \quad (263)$$

where,

$STGPIS_{r,t}$ = gross plant in service for existing and new capacity (dollars)
$STNPIS_{r,t}$ = net plant in service for existing and new capacity (dollars)
$STGPIS_E_{r,t}$ = gross plant in service for existing capacity (dollars)
$STGPIS_N_{r,t}$ = gross plant in service for new capacity (dollars)
$STNPIS_E_{r,t}$ = net plant in service for existing capacity (dollars)
$STNPIS_N_{r,t}$ = net plant in service for new capacity (dollars)
r = NGTDM region
t = forecast year

For the same reason as above, the accumulated depreciation, depletion, and amortization for t-1 can be split into its existing and new accumulated depreciation:

$$STADDA_{r,t-1} = STADDA_E_{r,t-1} + STADDA_N_{r,t-1} \quad (264)$$

where,

$STADDA_{r,t}$ = accumulated depreciation, depletion, and amortization for existing and new capacity (dollars)
$STADDA_E_{r,t}$ = accumulated depreciation, depletion, and amortization for existing capacity (dollars)
$STADDA_N_{r,t}$ = accumulated depreciation, depletion, and amortization for new capacity (dollars)
r = NGTDM region
t = forecast year

The accumulated depreciation for the current year t is expressed as last year's accumulated depreciation plus this year's depreciation. For the separate existing and new storage capacity, their accumulated depreciation, depletion, and amortization can be expressed separately as follows:

$$STADDA_E_{r,t} = STADDA_E_{r,t-1} + STDDA_E_{r,t} \quad (265)$$

$$STADDA_N_{r,t} = STADDA_N_{r,t-1} + STDDA_N_{r,t} \quad (266)$$

where,

$STADDA_E_{r,t}$ = accumulated depreciation, depletion, and amortization for existing capacity (dollars)

$STADDA_N_{r,t}$ = accumulated depreciation, depletion, and amortization for new capacity (dollars)

$STDDA_E_{r,t}$ = depreciation, depletion, and amortization for existing capacity (dollars)

$STDDA_N_{r,t}$ = depreciation, depletion, and amortization for new capacity (dollars)

r = NGTDM region

t = forecast year

Total accumulated depreciation, depletion, and amortization for the combined existing and new capacity by storage region in year t is determined as the sum of previous year's accumulated depreciation, depletion, and amortization and current year's depreciation, depletion, and amortization for that total capacity.

$$STADDA_{r,t} = STADDA_{r,t-1} + STDDA_{r,t} \quad (267)$$

where,

$STADDA_{r,t}$ = accumulated depreciation, depletion, and amortization for existing and new capacity in dollars

$STDDA_{r,t}$ = annual depreciation, depletion, and amortization for existing and new capacity in dollars

r = NGTDM region

t = forecast year

Computation of annual depreciation, depletion, and amortization, $STDDA_{r,t}$

Annual depreciation, depletion, and amortization for a storage region in year t is the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with that region.

$$STDDA_{r,t} = STDDA_E_{r,t} + STDDA_N_{r,t} \quad (268)$$

where,

$STDDA_{r,t}$ = annual depreciation, depletion, and amortization for existing and new capacity in dollars

$STDDA_E_{r,t}$ = depreciation, depletion, and amortization costs for existing capacity in dollars

$STDDA_N_{r,t}$ = depreciation, depletion, and amortization costs for new capacity in dollars

r = NGTDM region

t = forecast year

A regression equation is used to determine the annual depreciation, depletion, and amortization for existing capacity associated with an NGTDM region, while an accounting

algorithm is used for new storage capacity. For existing capacity, this depreciation expense by NGTDM region is forecast as follows:

$$STDDA_E_{r,t} = STDDA_CREG_r + STDDA_NPIS * STNPIS_E_{r,t-1} + STDDA_NEWCAP * STNEWCAP_{r,t} \quad (269)$$

where,

$STDDA_E_{r,t}$ = annual depreciation, depletion, and amortization costs for existing capacity in dollars
$STDDA_CREG_r$ = constant term estimated by region (Appendix F, Table F3)
STDDA_NPIS = estimated coefficient for net plant in service for existing capacity (Appendix F, Table F3)
STDDA_NEWCAP = estimated coefficient for the change in gross plant in service for existing capacity (Appendix F, Table F3)
$STNPIS_E_{r,t}$ = net plant in service for existing capacity (dollars)
$STNEWCAP_{r,t}$ = change in gross plant in service for existing capacity (dollars)
r = NGTDM region
t = forecast year

The accounting algorithm used to define the annual depreciation, depletion, and amortization for new capacity assumes straight-line depreciation over a 30-year life, as follows:

$$STDDA_N_{r,t} = STGPIS_N_{r,t} / 30 \quad (270)$$

where,

$STDDA_N_{r,t}$ = annual depreciation, depletion, and amortization for new capacity in dollars
$STGPIS_N_{r,t}$ = gross plant in service for new capacity in dollars
30 = 30 years of plant life
r = NGTDM region
t = forecast year

In the above equation, the capital cost of new plant in service ($STGPIS_N_{r,t}$) in year t is computed as the accumulated new capacity expansion expenditures from 1999 to year t and is determined by the following equation:

$$STGPIS_N_{r,t} = \sum_{s=1999}^{t} STNCAE_{r,s} \quad (271)$$

where,

$STGPIS_N_{r,t}$ = gross plant in service for new capacity expansion in dollars
$STNCAE_{r,s}$ = new capacity expansion expenditures occurring in year s after 1998 (in dollars)
s = the year new expansion occurred
r = NGTDM region
t = forecast year

The new capacity expansion expenditures allowed in the rate base within a forecast year are derived for each NGTDM region from the amount of incremental capacity additions determined by the ITS:

$$STNCAE_{r,t} = STCCOST_{r,t} * STCAPADD_{r,t} * 1{,}000{,}000. \quad (272)$$

where,

$STNCAE_{r,t}$ = total capital cost to expand capacity for an NGTDM region (dollars)
$STCCOST_{r,t}$ = capital cost per unit of natural gas storage expansion (dollars per Mcf)
$STCAPADD_{r,t}$ = storage capacity additions as determined in the ITS (Bcf/yr)
r = NGTDM region
t = forecast year

The capital cost per unit of natural gas storage expansion in an NGTDM region ($STCCOST_{r,t}$) is computed as its 1998 unit capital cost times a function of a capacity expansion factor relative to the 1998 storage capacity. This expansion factor represents a relative change in capacity since 1998. Whenever the ITS forecasts storage capacity additions in year t in an NGTDM region, the increased capacity is computed for that region from 1998 and the unit capital cost is computed. Hence, the capital cost to expand capacity in an NGTDM region can be estimated from any amount of capacity additions in year t provided by the ITS and the associated unit capital cost. This capital cost represents the investment cost for generic storage companies associated with that region. The unit capital cost ($STCCOST_{r,t}$) is computed by the following equations:

$$STCCOST_{r,t} = STCCOST_CREG_r * e^{(BETAREG_r * STEXPFAC98_r)} * (1.0 + STCSTFAC) \quad (273)$$

where,

$STCCOST_{r,t}$ = capital cost per unit of natural gas storage expansion (dollars per Mcf)
$STCCOST_CREG_r$ = 1998 capital cost per unit of natural gas storage expansion (1998 dollars per Mcf)
$BETAREG_r$ = expansion factor parameter (set to STCCOST_BETAREG, Appendix E)
$STEXPFAC98_r$ = relative change in storage capacity since 1998
STCSTFAC = factor to set a particular storage region's expansion cost, based on an average [Appendix E]
r = NGTDM region
t = forecast year

The relative change in storage capacity is computed as follows:

$$STEXPFAC98_r = \frac{PTCURPSTR_{r,t}}{PTCURPSTR_{r,1998}} - 1.0 \quad (274)$$

where,

$PTCURPSTR_{r,t}$ = current storage capacity (Bcf)
$PTCURPSTR_{r,1998}$ = 1998 storage capacity (Bcf)
r = NGTDM region
t = forecast year

Computation of total cash working capital, $STCWC_{r,t}$

The total cash working capital represents the level of working capital at the beginning of year t deflated using the chain weighted GDP price index with 1996 as a base year. This cash working capital variable is expressed as a non-linear function of total gas storage capacity (base gas capacity plus working gas capacity) as follows:

$$R_STCWC_{r,t} = e^{(STCWC_CREG_r * (1-\rho))} * DSTTCAP_{r,t-1}^{STCWC_TOTCAP} * R_STCWC_{r,t-1}^{\rho} * DSTTCAP_{r,t-2}^{-\rho * STCWC_TOTCAP} \quad (275)$$

where,

$R_STCWC_{r,t}$ = total cash working capital at the beginning of year t for existing and new capacity (1996 real dollars)
$STCWC_CREG_r$ = constant term, estimated by region (Appendix F, Table F3)
ρ = autocorrelation coefficient from estimation (Appendix F, Table F3 — STCWC_RHO)
$DSTTCAP_{r,t}$ = total gas storage capacity (Bcf)
STCWC_TOTCAP = estimated DSTTCAP coefficient (Appendix F, Table F3)
r = NGTDM region
t = forecast year

This total cash working capital in 1996 real dollars is converted to nominal dollars to be consistent with the convention used in this submodule.

$$STCWC_{r,t} = R_STCWC_{r,t} * \frac{MC_PCWGDP_t}{MC_PCWGDP_{1996}} \quad (276)$$

where,

$STCWC_{r,t}$ = total cash working capital at the beginning of year t for existing and new capacity (nominal dollars)
$R_STCWC_{r,t}$ = total cash working capital at the beginning of year t for existing and new capacity (1996 real dollars)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
r = NGTDM region
t = forecast year

Computation of accumulated deferred income taxes, $STADIT_{r,t}$

The level of accumulated deferred income taxes for the combined existing and new capacity in year t in the adjusted rate base equation is a stock (not a flow) and depends on income tax

regulations in effect, differences in tax, and book depreciation. It can be expressed as a linear function of its own lagged variable and the change in the level of gross plant in service between time t and t-1. The forecasting equation can be written as follows:

$$STADIT_{r,t} = STADIT_C + (STADIT_ADIT * STADIT_{r,t-1}) + (STADIT_NEWCAP * NEWCAP_{r,t}) \quad (277)$$

where,

$STADIT_{r,t}$ = accumulated deferred income taxes in dollars
STADIT_C = constant term from estimation (Appendix F, Table F3)
STADIT_ADIT = estimated coefficient for lagged accumulated deferred income taxes (Appendix F, Table F3)
STADIT_NEWCAP = estimated coefficient for change in gross plant in service (Appendix F, Table F3)
$NEWCAP_{r,t}$ = change in gross plant in service for the combined existing and new capacity between years t and t-1 (in dollars)
r = NGTDM region
t = forecast year

Computation of Total Taxes, $STTOTAX_{r,t}$

Total taxes consist of Federal income taxes, State income taxes, deferred income taxes, and other taxes. Federal income taxes and State income taxes are calculated using average tax rates. The equation for total taxes is as follows:

$$STTOTAX_{r,t} = STFSIT_{r,t} + STDIT_{r,t} + STOTTAX_{r,t} \quad (278)$$

$$STFSIT_{r,t} = STFIT_{r,t} + STSIT_{r,t} \quad (279)$$

where,

$STTOTAX_{r,t}$ = total Federal and State income tax liability for existing and new capacity (dollars)
$STFSIT_{r,t}$ = Federal and State income tax for existing and new capacity (dollars)
$STFIT_{r,t}$ = Federal income tax for existing and new capacity (dollars)
$STSIT_{r,t}$ = State income tax for existing and new capacity (dollars)
$STDIT_{r,t}$ = deferred income taxes for existing and new capacity (dollars)
STOTTAX = all other taxes assessed by Federal, State, or local governments for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the Federal tax rate. The after-tax profit is the operating income excluding the total long-term debt, which is determined as follows:

$$STATP_{r,t} = STAPRB_{r,t} * (STPFER_{r,t} * STGPFESTR_r + STCMER_{r,t} * STGCMESTR_r) \quad (280)$$

$$STATP_{r,t} = (STPFEN_{r,t} + STCMEN_{r,t}) \quad (281)$$

where,

$STATP_{r,t}$ = after-tax profit for existing and new capacity (dollars)
$STAPRB_{r,t}$ = adjusted pipeline rate base for existing and new capacity (dollars)
$STPFER_{r,t}$ = coupon rate for preferred stock for existing and new capacity (fraction)
$STGPFESTR_r$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$STCMER_{r,t}$ = common equity rate of return for existing and new capacity (fraction)
$STGCMESTR_r$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$STPFEN_{r,t}$ = total return on preferred stock for existing and new capacity (dollars)
$STCMEN_{r,t}$ = total return on common stock equity for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

and the Federal income taxes are

$$STFIT_{r,t} = (FRATE * STATP_{r,t}) / (1. - FRATE) \quad (282)$$

where,

$STFIT_{r,t}$ = Federal income tax for existing and new capacity (dollars)
FRATE = Federal income tax rate (fraction, Appendix E)
$STATP_{r,t}$ = after-tax profit for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

State income taxes are computed by multiplying the sum of taxable profit and the associated Federal income tax by a weighted-average State tax rate associated with each NGTDM region. State income taxes are computed as follows:

$$STSIT_{r,t} = SRATE * (STFIT_{r,t} + STATP_{r,t}) \quad (283)$$

where,

$STSIT_{r,t}$ = State income tax for existing and new capacity (dollars)
SRATE = average State income tax rate (fraction, Appendix E)
$STFIT_{r,t}$ = Federal income tax for existing and new capacity (dollars)
$STATP_{r,t}$ = after-tax profits for existing and new capacity (dollars)

r = NGTDM region
t = forecast year

Deferred income taxes for existing and new capacity at the arc level are the differences in the accumulated deferred income taxes between year t and year t-1.

$$STDIT_{r,t} = STADIT_{r,t} - STADIT_{r,t-1} \quad (284)$$

where,

$STDIT_{r,t}$ = deferred income taxes for existing and new capacity (dollars)
$STADIT_{r,t}$ = accumulated deferred income taxes for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

Other taxes consist of a combination of ad valorem taxes (which grow with company revenue), property taxes (which grow in proportion to gross plant), and all other taxes (assumed constant in real terms). Other taxes in year t are determined as the previous year's other taxes adjusted for inflation.

$$STOTTAX_{r,t} = STOTTAX_{r,t-1} * (MC_PCWGDP_t / MC_PCWGDP_{t-1}) \quad (285)$$

where,

$STOTTAX_{r,t}$ = all other taxes assessed by Federal, State, or local governments except income taxes for existing and new capacity (dollars) [read in as D_OTTAXr,t , t=1990-1998]
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
r = NGTDM region
t = forecast year

Computation of total operating and maintenance expenses, $STTOM_{r,t}$

The total operating and maintenance costs (including administrative costs) for existing and new capacity in an NGTDM region are determined in 1996 real dollars using a log-linear form with correction for serial correlation. The estimated equation is determined as a function of working gas storage capacity for region r at the beginning of period t. In developing the estimations, the impact of regulatory change and the differences between producing and consuming regions were analyzed.[93] Because their impacts were not supported by the data, they were not accounted for in the estimations. The final estimating equation is:

$$R_STTOM_{r,t} = e^{(STTOM_C*(1-\rho))} * DSTWCAP_{r,t-1}^{STTOM_WORKCAP} * R_STTOM_{r,t-1}^{\rho} * DSTWCAP_{r,t-2}^{-\rho*STTOM_WORKCAP} \quad (286)$$

[93]The gas storage industry changed substantially when in 1994 FERC Order 636 required jurisdictional pipeline companies to operate their storage facilities on an open-access basis. The primary customers and use of storage in producing regions are significantly different from consuming regions.

where,

$R_STTOM_{r,t}$ = total operating and maintenance cost for existing and new capacity (1996 real dollars)
STTOM_C = constant term from estimation (Appendix F, Table F3)
ρ = autocorrelation coefficient from estimation (Appendix F, Table F3 -- STTOM_RHO)
$DSTWCAP_{r,t}$ = level of gas working capacity for region r during year t
STTOM_WORKCAP = estimated DSTWCAP coefficient (Appendix F, Table F3)
r = NGTDM region
t = forecast year

Finally, the total operating and maintenance costs are converted to nominal dollars to be consistent with the convention used in this submodule.

$$STTOM_{r,t} = R_STTOM_{r,t} * \frac{MC_PCWGDP_t}{MC_PCWGDP_{1996}} \quad (287)$$

where,

$STTOM_{r,t}$ = total operating and maintenance costs for existing and new capacity (nominal dollars)
$R_STTOM_{r,t}$ = total operating and maintenance costs for existing and new capacity (1996 real dollars)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
r = NGTDM region
t = forecast year

Computation of Storage Tariff

The regional storage tariff depends on the storage cost of service, current working gas capacity, utilization rate, natural gas storage activity, and other factors. The functional form is similar to the pipeline tariff curve, in that it will be built from a regional base point [price and quantity (PNOD,QNOD)]. The base regional storage tariff ($PNOD_{r,t}$) is determined as a function of the cost of service ($STCOS_{r,t}$ (equation 244)) and other factors discussed below. $QNOD_{r,t}$ is set to an effective working gas storage capacity by region, which is defined as a regional working gas capacity times its utilization rate. Hence, once the storage cost of service is computed by region, the base point can be established. Minor adjustments to the storage tariff routine will be necessary in order to obtain the desired results.

In the model, the storage cost of service used represents only a portion of the total storage cost of service, the revenue collected from the customers for withdrawing during the peak period the quantity of natural gas stored during the off-peak period. This portion is defined as a user-set percentage (STRATIO, Appendix E) representing the portion (ratio) of revenue requirement obtained by storage companies for storing gas during the off-peak and withdrawing it for the customers during the peak period. This would include charges for injections, withdrawals, and reserving capacity.

The cost of service $STCOS_{r,t}$ is computed using the Foster storage financial database which represents only the storage facilities owned by the interstate natural gas pipelines in the U.S. which have filed a Form 2 financial report with the FERC. Therefore, an adjustment to this cost of service to account for all the storage companies by region is needed. For example, at the national level, the Foster database shows the underground storage working gas capacity at 2.3 Tcf in 1998 and the EIA storage gas capacity data show much higher working gas capacity at 3.8 Tcf. Thus, the average adjustment factor to obtain the "actual" cost of service across all regions in the U.S. is 165 percent. This adjustment factor, $STCAP_ADJ_{r,t}$, varies from region to region.

To complete the design of the storage tariff computation, two more factors need to be incorporated: the regional storage tariff curve adjustment factor and the regional efficiency factor for storage operations, which makes the storage tariff more competitive in the long-run.

Hence, the regional average storage tariff charged to customers for moving natural gas stored during the off-peak period and withdrawn during the peak period can be computed as follows:

$$PNOD_{r,t} = \frac{STCOS_{r,t}}{(MC_PCWGDP_t * QNOD_{r,t} * 1{,}000{,}000.)} * STRATIO_{r,t} * STCAP_ADJ_{r,t} * ADJ_STR * (1.0 - STR_EFF/100.)^t \quad (288)$$

where,

$$STCAP_ADJ_{r,t} = \frac{PTCURPSTR_{r,t}}{FS_PTCURPSTR_{r,t}} \quad (289)$$

$$QNOD_{r,t} = PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \quad (290)$$

and,

$PNOD_{r,t}$ = base point, price (87$/Mcf)
$STCOS_{r,t}$ = storage cost of service for existing and new capacity (dollars)
$QNOD_{r,t}$ = base point, quantity (Bcf)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
$STRATIO_{r,t}$ = portion of revenue requirement obtained by moving gas from the off-peak to the peak period (fraction, Appendix E)
$STCAP_ADJ_{r,t}$ = adjustment factor for the cost of service to total U.S. (ratio)
ADJ_STR = storage tariff curve adjustment factor (fraction, Appendix E)
STR_EFF = efficiency factor (percent) for storage operations (Appendix E)
$PTSTUTZ_{r,t}$ = storage utilization (fraction)
$PTCURPSTR_{r,t}$ = current storage capacity (Bcf)

$FS_PTCURPSTR_{r,t}$ = Foster storage working gas capacity (Bcf) [read in as D_WCAP]
r = NGTDM region
t = forecast year

Finally, the storage tariff curve by region can be expressed as a function of a base point [price and quantity (PNOD, QNOD)], storage flow, and a price elasticity, as follows:

current capacity segment:

$$X1NGSTR_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA_STR} \quad (291)$$

capacity expansion segment:

$$X1NGSTR_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA2_STR} \quad (292)$$

where,

$X1NGSTR_VARTAR_{r,t}$ = function to define storage tariffs (87$/Mcf)
$PNOD_{r,t}$ = base point, price (87$/Mcf)
$QNOD_{r,t}$ = base point, quantity (Bcf)
$Q_{r,t}$ = regional storage flow (Bcf)
ALPHA_STR = price elasticity for storage tariff curve for current capacity (Appendix E)
ALPHA2_STR = price elasticity for storage tariff curve for capacity expansion segment (Appendix E)
r = NGTDM region
t = forecast year

Alaska and MacKenzie Delta Pipeline Tariff Routine

A single routine (FUNCTION NGFRPIPE_TAR) estimates the potential per-unit pipeline tariff for moving natural gas from either the North Slope of Alaska or the MacKenzie Delta to the market hub in Alberta, Canada for the years beyond the specified in-service date. The tariff estimates are based on a simple cost-of-service rate base methodology, given the infrastructure's initial capital cost at the beginning of the construction period (FR_CAPITL0 in billion dollars, Appendix E), the assumed number of years for the project to be completed (FRPCNSYR, Appendix E), the associated discount rate for the project (FR_DISCRT, Appendix E), the initial capacity (a function of delivered volume FR_PVOL, Appendix E), and the number of years over which the final cost of capitalization is assumed completely amortized (INVEST_YR=15). The input values vary depending on whether the tariff being calculated is associated with a pipeline for Alaska or for MacKenzie Delta gas. The cost of service consists of the following four components: depreciation, depletion, and amortization; after-tax operating income (known as the return on rate base); total operating and maintenance expenses; and total income taxes. The computation of each of the four components in nominal dollars per Mcf is described below:

Depreciation, depletion, and amortization, FR_DDA_t

The depreciation is computed as the final cost of capitalization at the start of operations divided by the amortization period. The depreciation equation is provided below:

$$FR_DDA_t = FR_CAPITL1 / INVEST_YR \quad (293)$$

where,

FR_DDA_t = depreciation, depletion, and amortization costs (thousand nominal dollars)
FR_CAPITL1 = final cost of capitalization at the start of operations (thousand nominal dollars)
INVEST_YR = investment period allowing recovery (parameter, INVEST_YR=15)
t = forecast year

The structure of the final cost of capitalization, FR_CAPITL1, is computed as follows:

$$FR_CAPITL1 = FR_CAPIT0 / FR_PCNSYR * [(1+r) + (1+r)^2 + ... + (1+r)^{FR_PCNSYR}] \quad (294)$$

where,

FR_CAPITL1 = final cost of capitalization at the start of operations (thousand nominal dollars)
FR_CAPITL0 = initial capitalization (thousand FR_CAPYR dollars), where FR_CAPYR is the year dollars associated with this assumed capital cost (Appendix E)
FR_PCNSYR = number of construction years (Appendix E)
r = cost of debt, fraction, which is equal to the nominal 10-year Treasury bill (MC_RMTCM10Y or TNOTE, in percent) plus a debt premium in percent (debt premium set to FR_DISCRT, Appendix E)

The net plant in service is tied to the depreciation by the following formulas:

$$FR_NPIS_t = FR_GPIS_t - FR_ADDA_t$$
$$FR_ADDA_t = FR_ADDA_{t-1} + FR_DDA_t \quad (295)$$

where,

FR_GPIS_t = original capital cost of plant in service (gross plant in service) in thousand nominal dollars, set to FR_CAPITL1.
FR_NPIS_t = net plant in service (thousand nominal dollars)
FR_ADDA_t = accumulated depreciation, depletion, and amortization in thousand nominal dollars
t = forecast year

After-tax operating income (return on rate base), FR_TRRB_t

This after-tax operating income also known as the return on rate base is computed as the net plant in service times an annual rate of return (FR_ROR, Appendix E). The net plant in service, FR_NPIS_t, gets updated each year and is equal to the initial gross plant in service minus accumulated depreciation. Net plant in service becomes the adjusted rate base when other capital related costs such as materials and supplies, cash working capital, and accumulated deferred income taxes are equal to zero.

The return on rate base is computed as follows:

$$FR_TRRB_t = WACC_t * FR_NPIS_t \quad (296)$$

where,

$$WACC_t = FR_DEBTRATIO * COST_OF_DEBT_t + (1.0 - FR_DEBTRATIO) * COST_OF_EQUITY_t \quad (297)$$

and

$$COST_OF_DEBT_t = (TNOTE_t + FR_DISCRT)/100. \quad (298)$$

$$COST_OF_EQUITY_t = (TNOTE_t)/100. \quad (299)$$

where,

FR_TRRB_t = after-tax operating income or return on rate base (thousand nominal dollars)
$WACC_t$ = weighted average cost of capital (fraction), nominal
FR_NPIS_t = net plant in service (thousand nominal dollars)
$COST_OF_DEBT_t$ = cost of debt (fraction)
$COST_OF_EQUITY_t$ = cost of equity (fraction)
$TNOTE_t$ = nominal 10-year Treasury bill rate, ($MC_RMTCM10Y_t$, percent) provided by the Macroeconomic Activity Module
FR_DISCRT = user-set debt premium, percent (Appendix E)
FR_ROR_PREM = user-set risk premium, percent (Appendix E)
t = forecast year

Total taxes, FR_TAXES_t

Total taxes consist of Federal and State income taxes and taxes other than income taxes. Each tax category is computed based on a percentage times net profit. These percentages are drawn from the Foster financial report's 28 major interstate natural gas pipeline companies. The percentage for income taxes (FR_TXR) is computed as the average over five years (1992-1996) of tax to net operating income ratio from the Foster report. Likewise, the percentage (FR_OTXR) for taxes other than income taxes is computed as the average over five years (1992-1996) of taxes other than income taxes to net operating income ratio from the same report. Total taxes are computed as follows:

$$FR_TAXES_t = (FR_TXR + FR_OTXR) * FR_NETPFT_t \quad (300)$$

where,

FR_TAXES_t = total taxes (thousand nominal dollars)
FR_NETPFT_t = net profit (thousand nominal dollars)
FR_TXR = 5-year average Lower 48 pipeline income tax rate, as a proxy (Appendix E)
FR_OTXR = 5-year average Lower 48 pipeline other income tax rate, as a proxy (Appendix E)
t = forecast year

Net profit, FR_NETPFT, is computed as the return on rate base (FR_TRRB_t) minus the long-term debt (FR_LTD_t), which is calculated as the return on rate base times long-term debt rate times the debt to capital structure ratio. The net profit and long-term debt equations are provided below:

$$FR_NETPFT_t = (FR_TRRB_t - FR_LTD_t) \quad (301)$$

$$FR_LTD_t = FR_DEBTRATIO * (TNOTE_t + FR_DISCRT) / 100.0 * FR_NPIS_t \quad (302)$$

where,

FR_LTD_t = long-term debt (thousand nominal dollars)
FR_NPIS_t = net plant in service (thousand nominal dollars)
FR_DEBTRATIO = 5-year average Lower 48 pipeline debt structure ratio (Appendix E)
FR_NETPFT_t = net profit (thousand nominal dollars)
FR_TRRB_t = return on rate base (thousand nominal dollars)
$TNOTE_t$ = nominal 10-year Treasury bill, (MC_RMTCM10Y, percent) provided by the Macroeconomic Activity Module
FR_DISCRT = user-set debt premium, percent (Appendix E)
t = forecast year

In the above equations, the long-term debt rate is assumed equal to the 10-year Treasury bill plus a debt premium, which represents a risk premium generally charged by financial institutions. When 10-year Treasury bill rates are needed for years beyond the last forecast year (LASTYR), the variable $TNOTE_t$ becomes the average over a number of years (FR_ESTNYR, Appendix E) of the 10-year Treasury bill rates for the last forecast years.

Cost of Service, FR_COS_t

The cost of service is the sum of four cost-of-service components computed above, as follows:

$$FR_COS_t = (FR_TRRB_t + FR_DDA_t + FR_TAXES_t + FR_TOM_{FR_CAPYR} * (MC_PCWGDP_t / MC_PCWGDP_{FR_CAPYR}) * FR_PVOL * 1.1484 * 1000.0) \quad (303)$$

where,

FR_COS_t = cost of service (thousand nominal dollars)
FR_TRRB_t = return on rate base (thousand nominal dollars)
FR_DDA_t = depreciation (thousand nominal dollars)
FR_TAXES_t = total taxes (thousand nominal dollars)
FR_TOMFR_CAPYR = total operating and maintenance expenses (in nominal dollars per Mcf, set constant in real terms) (Appendix E)
MC_PCWGDP_t = GDP price deflator (from Macroeconomic Activity Module)
FR_PVOL = maximum volume delivered to Alberta in dry terms (Bcf/year)
1.1484 = factor to convert delivered dry volume to wet gas volume entering the pipeline as a proxy for the pipeline capacity
t = forecast year

Hence, the annual pipeline tariff in nominal dollars is computed by dividing the above cost of service by total pipeline capacity, as follows:

$$COS_t = FR_COS_t / (FR_PVOL * 1.1484 * 1000.0) \quad (304)$$

where,

COS_t = per-unit cost of service or annual pipeline tariff (nominal dollars/Mcf)
t = forecast year

To convert this nominal tariff to real 1987$/Mcf, the GDP implicit price deflator variable provided by the Macroeconomic Activity Module is needed. The real tariff equation is written as follows:

$$COSR_t = COS_t / MC_PCWGDP_t \quad (305)$$

where,

$COSR_t$ = annual real pipeline tariff (1987 dollars/Mcf)
MC_PCWGDP_t = GDP price deflator (from Macroeconomic Activity Module)
t = forecast year

Last, the annual average tariff is computed as the average over a number of years (FR_AVGTARYR, Appendix E) of the first successive annual cost of services.

7. Model Assumptions, Inputs, and Outputs

This last chapter summarizes the model and data assumptions used by the Natural Gas Transmission and Distribution Module (NGTDM) and lists the primary data inputs to and outputs from the NGTDM.

Assumptions

This section presents a brief summary of the assumptions used within the NGTDM. Generally, there are two types of data assumptions that affect the NGTDM solution values. The first type can be derived based on historical data (past events), and the second type is based on experience and/or events that are likely to occur (expert or analyst judgment). A discussion of the rationale behind assumed values based on analyst judgment is beyond the scope of this report. Most of the FORTRAN variables related to model input assumptions, both those derived from known sources and those derived through analyst judgment, are identified in this chapter, with background information and actual values referenced in Appendix E.

The assumptions summarized in this section are mentioned in Chapters 2 through 6. They are used in NGTDM equations as starting values, coefficients, factors, shares, bounds, or user specified parameters. Six general categories of data assumptions have been defined: classification of market services, demand, transmission and distribution service pricing, pipeline tariffs and associated regulation, pipeline capacity and utilization, and supply (including imports). These assumptions, along with their variable names, are summarized below.

Market Service Classification

Nonelectric sector natural gas customers are classified as either core or noncore customers, with core customers defined as the type of customer that is expected to generally transport their gas under firm (or near firm) transportation agreements and noncore customers to generally transport their gas under non-firm (interruptible or short-term capacity release) transportation agreements. The residential, commercial, and transportation (natural gas vehicles) sectors are assumed to be core customers. The transportation sector is further subdivided into fleet and personal vehicle customers. Industrial and electric generator end users fall into both categories, with industrial boilers and refineries assumed to be noncore and all other industrial users assumed to be core, and gas steam units or gas combined cycle units assumed to be core and all other electric generators assumed to be noncore. Currently the core/noncore distinction for electric generators is not being used in the model.

Demand

The peak period is defined *(using PKOPMON)* to run from December through March, with the off-peak period filling up the remainder of the year.

The Alaskan natural gas consumption levels for residential and commercial sectors are primarily defined as a function of the number of customers *(AK_RN, AK_CM, Tables F1, F2)*, which in turn are set based on an exogenous projection of the population in Alaska *(AK_POP)*. Alaskan gas consumption is disaggregated into North and South Alaska in order to separately compute the natural gas production forecasts in these regions. Lease, plant, and pipeline fuel related to an Alaska pipeline or a gas-to-liquids facility are set at an assumed percentage of their associated gas volumes *(AK_PCTPLT, AK_PCTPIP, AK_PCTLSE)*. The remaining lease and plant fuel is assumed to be consumed in the North and set based on historical trends. The amount of gas consumed by other sectors in North Alaska is small enough to assume as zero and to allow for the setting of South Alaska volumes equal to the totals for the State. Industrial consumption in South Alaska is set to the exogenously specified sum of the level of gas consumed at the Agrium fertilizer plant and at the liquefied natural gas plant *(AK_QIND_S)*. Pipeline fuel in the South is set as a percentage *(AK_PCTPIP)* of consumption and exports. Production in the south is set to total consumption levels in the region. In the north production equals the flow along an Alaska pipeline to Alberta, any gas needed to support the production of gas-to-liquids, associated lease, plant, and pipeline fuel for these two applications, and the other calculated lease and plant fuel. The forecast for reporting discrepancy in Alaska *(AK_DISCR)* is set to an average historical value. To compute natural gas prices by end-use sector for Alaska, fixed markups derived from historical data *(AK_RM, AK_CM, AK_IN, AK_EM)* are added to the average Alaskan natural gas wellhead price over the North and South regions. The wellhead price is set using a simple estimated equation *(AK_F)*. Historically based percentages and markups are held constant throughout the forecast period.

The shares *(NG_CENSHR)* for disaggregating nonelectric Census Division demands to NGTDM regions are held constant throughout the forecast period and are based on average historical relationships *(SQRS, SQCM, SQIN, SQTR)*. Similarly, the shares for disaggregating end-use consumption levels to peak and off-peak periods are held constant throughout the forecast, and are directly *(United States -- PKSHR_DMD, PKSHR_UDMD_F, PKSHR_UDMD_I)* or partially *(Canada -- PKSHR_CDMD)* historically based. Canadian consumption levels are set exogenously *(CN_DMD)* based on another published forecast, and adjusted if the associated world oil price changes. Consumption, base level production, and domestically consumed LNG imports into Mexico are set exogenously *(PEMEX_GFAC, IND_GFAC, ELE_GFAC, RC_GFAC, PRD_GFAC, MEXLNG)*. After the base level production is adjusted based on the average U.S. wellhead price, exports to Mexico are set to balance supply and consumption. Historically based shares *(PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, PKSHR_ILNG)* are applied to projected/historical values for natural gas exports and imports *(SEXP, SIMP, CANEXP, Q23TO3, FLO_THRU_IN,OGQNGEXP)*. These historical based shares are generated from monthly historical data *(QRS, QCM, QIN, QEU, MON_QEXP, MON_QIMP)*.

Lease and plant fuel consumption in each NGTDM region is computed as an historically derived percentage *(using SQLP)* of dry gas production *(PCTLP)* in each NGTDM/OGSM region. These percentages are held constant throughout the forecast period. Pipeline fuel use is

derived using historically *(SQPF)* based factors *(PFUEL_FAC)* relating pipeline fuel use to the quantity of natural gas exiting a regional node. Values for the most recent historical year are derived from monthly-published figures *(QLP_LHIS, NQPF_TOT)*.

Pricing of Distribution Services

End-use prices for residential, commercial, industrial, transportation, and electric generation customers are derived by adding markups to the regional hub price of natural gas. Each regional end-use markup consists of an intraregional tariff *(INTRAREG_TAR)*, an intrastate tariff *(INTRAST_TAR)*, a distribution tariff *(endogenously defined)*, and a city gate benchmark factor [endogenously defined based on historical seasonal city gate prices (HCGPR)]. Historical distributor tariffs are derived for all sectors as the difference between historical city gate and end-use prices *(SPRS, SPCM, SPIN, SPEU, SPTR, PRS, PCM PIN, PEU)*.[94] Historical industrial end-use prices are derived in the module using an econometrically estimated equation (Table F5).[95] The residential, commercial, industrial, and electric generator distributor tariffs are also based on econometrically estimated equations (Tables F4, F6, F7, and F8). The distributor tariff for the personal (PV) and fleet vehicle (FV) components of the transportation sector are set using historical data, a decline rate *(TRN_DECL)*, state and federal taxes *(STAX, FTAX)*, and assumed dispensing costs/charges *(RETAIL_COST)*, and for personal vehicles at retail stations, a capital cost recovery markup *(CNG_RETAIL_MARKUP)*.

Prices for exports (and fixed volume imports) are based on historical differences between border prices *(SPIM, SPEX, MON_PIMP, MON_PEXP)* and their closest market hub price (as determined in the module when executed during the historical years).

Pipeline and Storage Tariffs and Regulation

Peak and off-peak transportation rates for interstate pipeline services (both between NGTDM regions and within a region) are calculated assuming that the costs of new pipeline capacity will be rolled into the existing rate base. Peak and off-peak market transmission service rates are based on a cost-of-service/rate-of-return calculation for current pipeline capacity times an assumed utilization rate *(PKUTZ, OPUTZ)*. To reflect recent regulatory changes related to alternative ratemaking and capacity release developments, these tariffs are discounted (based on an assumed price elasticity) as pipeline utilization rates decline.

In the computation of natural gas pipeline transportation and storage rates, the Pipeline Tariff Submodule uses a set of data assumptions based on historical data or expert judgment. These include the following:

[94] All historical prices are converted from nominal to real 1987 dollars using a price deflator *(GDP_B87)*.

[95] Traditionally industrial prices have been derived by collecting sales data from local distribution companies. More recently, industrial customers have not relied on LDCs to purchase their gas. As a result, annually published industrial natural gas prices only represent a rather small portion of the total population. In the module, these published prices are adjusted using an econometrically estimated equation based on EIA's survey of manufacturers to derive a more representative set of industrial prices.

- Factors *(AFX, AFR, AVR)* to allocate each company's line item costs into the fixed and variable cost components of the reservation and usage fees
- Capacity reservation shares used to allocate cost of service components to portions of the pipeline network
- Average pipeline capital cost (2005 dollars) per unit of expanded capacity by arc *(AVGCOST)* used to derive total capital costs to expand pipeline capacity
- Storage capacity expansion cost parameters *(STCCOST_CREG, STCCOST_BETAREG, STCSTFAC)* used to derive total capital costs to expand regional storage capacity
- Input coefficients *(ALPHA_PIPE, ALPH2_PIPE, ALPHA_STR, ALPHA2_STR, ADJ_STR, STR_EFF)* for transportation and storage rates
- Pipeline tariff curve parameters by arc *(PKSHR_YR, PTPKUTZ, PTOPUTZ, ALPHA_PIPE, ALPHA2_PIPE)*
- Storage tariff curve parameters by region *(STRATIO, STCAP_ADJ, PTSTUTZ, ADJ_STR, STR_EFF, ALPHA_STR, ALPHA2_STR)*

In order to determine when a pipeline from either Alaska or the MacKenzie Delta to Alberta could be economic, the model estimates the tariff that would be charged on both pipelines should they be built, based on a number of assumed values. A simple cost-of-service/rate-of-return calculation is used, incorporating the following: initial capitalization *(FR_CAPITLO)*, return on debt *(FR_DISCRT)* and return on equity *(FR_ROR_PREM)* (both specified as a premium added to the 10-year Treasury bill rate), total debt as a fraction of total capital *(FR_DEBTRATIO)*, operation and maintenance expenses *(FR_TOM0)*, federal income tax rate *(FR_TXR)*, other tax rate *(FR_OTXR)*, levelized cost period *(FR_AVGTARYR)*, and depreciation period *(INVEST_YR)*. In order to establish the ultimate charge for the gas in the lower 48 States assumptions were made for the minimum wellhead price *(FR_PMINWPC)* including production, treatment, and fuel costs, as well as the average differential between Alberta and the lower 48 *(ALB_TO_L48)* and a risk premium *(FR_PRISK)* to reflect cost and market uncertainties. The market price in the lower 48 states must be maintained over a planning horizon *(FR_PPLNYR)* before construction would begin. Construction is assumed to take a set number of years *(FR_PCNSYR)* and result in a given initial capacity based on initial delivered volumes *(FR_PVOL)*. An additional expansion is assumed on the condition of an increase in the market price *(FR_PADDTAR, FR_PEXPFAC)*.

Pipeline and Storage Capacity and Utilization

Historical and planned interregional, intraregional, and Canadian pipeline capacities are assigned in the module for the historical years and the first few years *(NOBLDYR)* into the forecast *(ACTPCAP, PTACTPCAP, PLANPCAP, SPLANPCAP, PER_YROPEN, CNPER_YROPEN)*. The flow of natural gas along these pipeline corridors in the peak and off-peak periods of the historical years is set, starting with historical shares *(HPKSHR_FLOW)*, to be consistent with the annual flows *(HAFLOW, SAFLOW)* and other known seasonal network volumes (e.g., consumption, production).

A similar assignment is used for storage capacities *(PLANPCAP, ADDYR)*. The module only represents net storage withdrawals in the peak period and net storage injections in the off-peak period, which are known historically *(HNETWTH, HNETINJ, SNETWTH, NWTH_TOT, NINJ_TOT)*.

For the forecast years, the use of both pipeline and storage capacity in each seasonal period is limited by exogenously set maximum utilization rates *(PKUTZ, OPUTZ, SUTZ)*, although these are

currently not active for pipelines. They were originally intended to reflect an expected variant in the load throughout a season. Adjustments are now being made within the module, during the flow sharing algorithm, to reflect the seasonal load variation.

The decision concerning the share of gas that will come from each incoming source into a region for the purpose of satisfying the regions consumption levels (and some of the consumption upstream) is based on the relative costs of the incoming sources and assumed parameters *(GAMMAFAC, MUFAC)*. During the process of deciding the flow of gas through the network, an iterative process is used that requires a set of assumed parameters for assessing and responding to nonconvergence *(PSUP_DELTA, QSUP_DELTA, QSUP_SMALL, QSUP_WT, MAXCYCLE)*.

Supply

The supply curves for domestic lower 48 nonassociated dry gas production and for conventional and tight gas production from the WCSB are based on an expected production level, the former of which is set in the OGSM. Expected production from the WCSB is set in the NGTDM using a series of three econometric equations for new successful wells drilled, quantity proved per well drilled, and expected quantity produced per current level proved, and is dependent on resource assumptions *(RESBASE, RESTECH)*. A set of parameters *(PARM_SUPCRV3, PARM_SUPCRV5, SUPCRV, PARM_SUPELAS)* defines the price change from a base or expected price as production deviates from this expected level. These supply curves are limited by minimum and maximum levels, calculated as a factor *(PARM_MINPR, MAXPRRFAC, MAXPRRCAN)* times the expected production levels. Domestic associated-dissolved gas production is provided by the Oil and Gas Supply Module. Eastern Canadian production from other than the WCSB is set exogenously *(CN_FIXSUP)*. Natural gas production in Canada from both coal beds and shale is based on assumed production withdrawal profiles from their perspective resource base totals *(ULTRES, ULTSHL)* at an assumed exogenously specified price path and is adjusted relative to how much the actual western Canadian price differs from the assumed. Production from the frontier areas in Canada (i.e., the MacKenzie Delta) is set based on the assumed size of the pipeline to transport the gas to Alberta, should the pipeline be built. Production from Alaska is a function of the consumption in Alaska and the potential capacity of a pipeline from Alaska to Alberta and/or a gas-to-liquids facility.

Imports from Mexico and Canada at each border crossing point are represented as follows: (1) Mexican imports are set exogenously *(EXP_FRMEX)* with the exception of LNG imported into Baja for U.S. markets; (2) Canadian imports are set endogenously (except for the imports into the East North Central region, *(Q23TO3)* and limited to Canadian pipeline capacities *(ACTPCAP, CNPER_YROPEN)*, which are set in the module, and expand largely in response to the introduction of Alaskan gas into the Alberta system. Total gas imports from Canada exclude the amount of gas that travels into the United States and then back into Canada *(FLO_THRU_IN)*.

Liquefied natural gas imports are represented with an east and west supply curves to North America generated based on output results from EIA's International Natural Gas Model and shared to representative regional terminals based on regasification capacity, last year's imports, and relative prices. Regasification capacity is set based on known facilities, either already constructed or highly likely to be *(LNGCAP)*.

The three supplemental production categories (synthetic production of natural gas from coal and liquids and other supplemental fuels) are represented as constant supplies within the Interstate Transmission Submodule, with the exception of any production from potential new coal-to-gas plants. Synthetic production from the existing coal plant is set exogenously *(SNGCOAL)*. Forecast values for the other two categories are held constant throughout the forecast and are set to historical values *(SNGLIQ, SUPPLM)* within the module. The algorithm for determining the potential construction of new coal-to-gas plants uses an extensive set of detailed cost figures to estimate the total investment and operating costs of a plant (including accounting for emissions costs, electricity credits, and lower costs over time due to learning) for use within a discounted cash flow calculation. If positive cash flow is estimated to occur the number of generic plants built is based on a Mansfield-Blackman market penetration algorithm. Throughout the forecast, the annual synthetic gas production levels are split into seasonal periods using an historically *(NSUPLM_TOT)* based share *(PKSHR_SUPLM)*.

The supply component uses an assortment of input values in defining historical production levels and prices (or revenues) by the regions and categories required by the module *(QOF_ALST, QOF_ALFD, QOF_LAST, QOF_LAFD, QOF_CA, ROF_CA, QOF_LA, ROF_LA, QOF_TX, ROF_TX, AL_ONSH, AL_OFST, AL_OFFD, LA_ONSH, LA_OFST, lA_OFFD , ADW, NAW, TGD, MISC_ST, MISC_GAS, MISC_OIL, SMKT_PRD, SDRY_PRD, HQSUP, HPSUP, WHP_LHIS, SPWH)*. A set of seasonal shares *(PKSHR_PROD)* have been defined based on historical values *(MONMKT_PRD)* to split production levels of supply sources that are nonvariant with price *(CN_FIXSUP and others)* into peak and off-peak categories.

Discrepancies that exist between historical supply and disposition level data are modeled at historical levels *(SBAL_ITM)* in the NGTDM and kept constant throughout the forecast years at average historical levels *(DISCR, CN_DISCR)*.

Model Inputs

The NGTDM inputs are grouped into six categories: mapping and control variables, annual historical values, monthly historical values, Alaskan and Canadian demand/supply variables, supply inputs, pipeline and storage financial and regulatory inputs, pipeline and storage capacity and utilization related inputs, end-use pricing inputs, and miscellaneous inputs. Short input data descriptions and identification of variable names that provide more detail (via Appendix E) on the sources and transformation of the input data are provided below.

Mapping and Control Variables

- Variables for mapping from States to regions *(SNUM_ID, SCH_ID, SCEN_DIV, SITM_REG, SNG_EM, SNG_OG, SIM_EX, MAP_PRDST)*
- Variables for mapping import/export borders to States and to nodes *(CAN_XMAPUS, CAN_XMAPCN, MEX_XMAP, CAN_XMAP)*
- Variables for handling and mapping arcs and nodes *(PROC_ORD,ARC_2NODE, NODE_2ARC, ARC_LOOP, SARC_2NODE, SNODE_2ARC, NODE_ANGTS, CAN_XMAPUS)*
- Variables for mapping supply regions *(NODE_SNGCOAL, MAPLNG_NG, OCSMAP, PMMMAP_NG, SUPSUB_NG, SUPSUB_OG)*
- Variables for mapping demand regions *(EMMSUB_NG, EMMSUB_EL, NGCENMAP)*

Annual Historical Values

- Offshore natural gas production and revenue data (QOF_ALST, QOF_ALFD, QOF_LAST, QOF_LAFD, QOF_CA, ROF_CA, QOF_LA, ROF_LA, QOF_TX, ROF_TX, QOF_AL, ROF_AL, QOF_MS, ROF_MS, QOF_GM, ROF_GM, PRICE_CA, PRICE_LA, PRICE_AL, PRICE_TX, GOF_LA, GOF_AL, GOF_TX, GOF_CA, AL_ONSH, AL_OFST, AL_OFFD, LA_ONSH, LA_OFST, LA_OFFD, AL_ONSH2, AL_OFST2, AL_ADJ)
- State-level supply prices *(SPIM, SPWH)*
- State/sub-state-level natural gas production and other supply/storage data *(ADW, NAW, TGD, TGW, MISC_ST, MISC_GAS, MISC_OIL, SMKT_PRD, SDRY_PRD, SIMP, SNET_WTH, SUPPLM)*
- State-level consumption levels *(SBAL_ITM, SEXP, SQPF, SQLP, SQRS, SQCM, SQIN, SQEU, SQTR)*
- State-level end-use prices *(SPEX, SPRS, SPCM, SPIN, SPEU, SPTR)*
- Miscellaneous *(GDP_B87, OGHHPRNG)*

Monthly Historical Values

- State-level natural gas production data *(MONMKT_PRD)*
- Import/export volumes and prices by source *(MON_QIMP, MON_PIMP, MON_QEXP, MON_PEXP, HQIMP)*
- Storage data *(NWTH_TOT, NINJ_TOT, HNETWTH, HNETINJ)*
- State-level consumption and prices *(CON & PRC -- QRS, QCM, QIN, QEU, PRS, PCM, PIN, PEU)*
- Electric power gas consumption and prices *(CON_ELCD, PRC_EPMCD, CON_EPMGR, PRC_EPMGR)*
- Miscellaneous monthly/seasonal data *(NQPF_TOT, NSUPLM_TOT, WHP_LHIS, QLP_LHIS, HCGPR)*

Alaskan, Canadian, & Mexican Demand/Supply Variables

- Alaskan lease, plant, and pipeline fuel parameters *(AK_PCTPLT, AK_PCTPIP, AK_PCTLSE)*
- Alaskan consumption parameters *(AK_QIND_S, AK_RN, AK_CM, AK_POP, AK_HDD, HI_RN)*
- Alaskan pricing parameters *(AK_RM, AK_CM, AK_IN, AK_EM)*
- Canadian production and end-use consumption *(CN_FIXSUP, CN_DMD, PKSHR_PROD, PKSHR_CDMD)*
- Exogenously specified Canadian import/export related volumes *(CANEXP, Q23TO3, FLO_THRU_IN)*
- Historical western Canadian production and wellhead prices *(HQSUP, HPSUP)*
- Unconventional western Canadian production parameters *(ULTRES, ULTSHL, RESBASE, PKIYR, LSTYR0, PERRES, RESTECH, TECHGRW)*
- Mexican production, LNG imports, and end-use consumption *(PEMEX_GFAC, IND_GFAC,ELE_GFAC,RC_GFAC, PRD_GFAC, MEXLNG)*

Supply Inputs

- Liquefied natural gas supply curves and pricing *(LNGCAP, PARM_LNGCRV3, PARM_LNGCRV5,PARM_LNGELAS, LNGPPT, LNGQPT, LNGMIN,PERQ, BETA,LNGTAR)*
- Supply curve parameters *(SUPCRV, PARM_MINPR, PARM_SUPCRV3, PARM_SUPCRV5, PARM_SUPELAS, MAXPRRFAC, MAXPRRNG, PARM_MINPR)*
- Synthetic natural gas projection *(SNGCOAL, SNGLIQ, NRCI_INV, NRCI_LABOR_NRCI_OPER,INFL_RT, FEDTAX_RT, STTAX_RT, INS_FAC, TAX_FAC, MAINT_FAC, OTH_FAC,BEQ_OPRAVG, BEQ_OPRHRSK, EMRP_OPRAVG, EMRP_OPRHRSK, EQUITY_OPRAVG, EQUITY_OPRHRSK, BEQ_BLDAVG, BEQ_BLDHRSK, EMRP_BLDAVG, EMRP_BLDHRSK, EQUITY_BLDAVG, EQUITY_BLDHRSK, BA_PREM, PCLADJ, CTG_CAPYR$, PRJSDECOM, CTG_BLDYRS, CTG_PRJLIFE, CTG_OSBLFAC, CTG_PCTENV, CTG_PCTCNTG, CTG_PCTLND, CTG_PCTSPECL, CTG_PCTWC, CTG_STAFF_LCFAC, CTG_OH_LCFAC, CTG_FSIYR, CTG_INCBLD, CTG_DCLCAPCST, CTG_DCLOPRCST, CTG_BASHHV, CTG_BASCOL, CTG_BCLTON, CTG_BASSIZ, CTG_BASCGS, CTG_BASCGSCO2, CTG_BASCGG, CTG_BASCGGCO2,CTG_NCL, CTG_NAM, CTG_CO2,LABORLOC, CTG_PUCAP, XBM_ISBL, XBM_LABOR, CTG_BLDX, CTG_IINDX, CTG_SINVST)*

Pipeline and Storage Financial and Regulatory Inputs

- Rate design specification *(AFX_PFEN, AFR_PFEN, AVR_PFEN, AFX_CMEN, AFR_CMEN, AVR_CMEN, AFX_LTDN, AFR_LTDN, AVR_LTDN, AFX_DDA, AFR_DDA, AVR_DDA, AFX_FSIT, AFR_FSIT, AVR_FSIT, AFX_DIT, AFR_DIT, AVR_DIT, AFX_OTTAX, AFR_OTTAX, AVR_OTTAX, AFX_TOM, AFR_TOM, AVR_TOM)*
- Pipeline rate base, cost, and volume parameters *(D_TOM, D_DDA, D_OTTAX, D_DIT, D_GPIS, D_ADDA, D_NPIS, D_CWC, D_ADIT, D_APRB, D_GPFES, D_GCMES, D_GLTDS, D_PFER, D_CMER, D_LTDR)*
- Storage rate base, cost, and volume parameters *(D_TOM, D_DDA, D_ADDA, D_OTTAX, D_FSIT, D_DIT, D_LTDN, D_PFEN, D_CMEN, D_GPIS, D_NPIS, D_CWC, D_ADIT, D_APRB, D_LTDS, D_PFES, D_CMES, D_TCAP, D_WCAP)*
- Pipeline and storage revenue requirement forecasting equation parameters *(Table F3)*
- Rate of return set for generic pipeline companies *(MC_RMPUAANS, ADJ_PFER, ADJ_CMER, ADJ_LTDR)*
- Rate of return set for existing and new storage capacity *(MC_RMPUAANS, ADJ_STPFER, ADJ_STCMER, ADJ_STLTDR)*
- Federal and State income tax rates *(FRATE, SRATE)*
- Depreciation schedule *(30 year life)*
- Pipeline capacity expansion cost parameter for capital cost equations *(AVGCOST)*
- Pipeline capacity replacement cost parameter *(PCNT_R)*
- Storage capacity expansion cost parameters for capital cost equations *(STCCOST_CREG, STCCOST_BETAREG, STCSTFAC)*
- Parameters for interstate pipeline transportation rates *(PKSHR_YR, PTPKUTZ, PTOPUTZ, ALPHA_PIPE, ALPHA2_PIPE)*
- Canadian pipeline and storage tariff parameters *(ARC_FIXTAR, ARC_VARTAR, CN_FIXSHR)*
- Parameters for storage rates *(STRATIO, STCAP_ADJ, PTSTUTZ, ADJ_STR, STR_EFF, ALPHA_STR, ALPHA2_STR)*
- Parameters for Alaska-to-Alberta and MacKenzie Delta-to-Alberta pipelines *(FR_CAPITL0, FR_CAPYR, FR_PCNSYR, FR_DISCRT, FR_PVOL, INVEST_YR,FR_ROR_PREM, FR_TOM0, FR_DEBTRATIO, FR_TXR, FR_OTXR, FR_ESTNYR, FR_AVGTARYR)*

Pipeline and Storage Capacity and Utilization Related Inputs

- Canadian natural gas pipeline capacity and planned capacity additions *(ACTPCAP, PTACTPCAP, PLANPCAP, CNPER_YROPEN)*
- Maximum peak and off-peak primary and secondary pipeline utilizations *(PKUTZ, OPUTZ, SUTZ, MAXUTZ, XBLD)*
- Interregional planned pipeline capacity additions along primary and secondary arcs (PLANPCAP, SPLANPCAP, PER_YROPEN)
- Maximum storage utilization (PKUTZ)
- Existing storage capacity and planned additions *(PLANPCAP, ADDYR)*
- Net storage withdrawals (peak) and injections (off-peak) in Canada *(HNETWTH, HNETINJ)*
- Historical flow data *(HPKSHR_FLOW, HAFLOW, SAFLOW)*
- Alaska-to-Alberta and MacKenzie Delta-to-Alberta pipeline *(FR_PMINYR, FR_PVOL, FR_PCNSYR, FR_PPLNYR, FR_PEXPFAC, FR_PADDTAR, FR_PMINWPR, FR_PRISK, FR_PDRPFAC, FR_PTREAT, FR_PFUEL)*

End-Use Pricing Inputs

- Residential, commercial, industrial, and electric generator distributor tariffs *(OPTIND, OPTCOM, OPTRES, OPTELP, OPTELO, RECS_ALIGN, NUM_REGSHR, HHDD)*
- Intrastate and intraregional tariffs *(INTRAST_TAR, INTRAREG_TAR)*
- Historical city gate prices *(HCGPR)*

- State and Federal taxes, costs to dispense, and other compressed natural gas pricing and infrastructure development parameters *(STAX, FTAX, RETAIL_COST, NSTAT, TRN_DECL, MAX_CNG_BUILD, CNG_HRZ, CNG_WACC, CNG_BUILDCOST)*

Miscellaneous

- Network processing control variables *(MAXCYCLE, NOBLDYR,ALPHAFAC, GAMMAFAC, PSUP_DELTA, QSUP_DELTA, QSUP_SMALL, QSUP_WT, PCT_FLO, SHR_OPT, PCTADJSHR)*
- Miscellaneous control variables *(PKOPMON, NGDBGRPT, SHR_OPT, NOBLDYR)*
- STEO input data *(STEOYRS, STQGPTR, STQLPIN, STOGWPRNG, STPNGRS, STPNGIN, STPNGCM, STPNGEL, STOGPRSUP, NNETWITH, STDISCR, STENDCON, STSCAL_CAN, STINPUT_SCAL, STSCAL_PFUEL, STSCAL_LPLT, STSCAL_WPR, STSCAL_DISCR, STSCAL_SUPLM, STSCAL_NETSTR, STSCAL_FPR, STSCAL_IPR, STPHAS_YR, STLNGIMP)*

Model Outputs

Once a set of solution values are determined within the NGTDM, those values required by other modules of NEMS are passed accordingly. In addition, the NGTDM module results are presented in a series of internal and external reports, as outlined below.

Outputs to NEMS Modules

The NGTDM passes its solution values to different NEMS modules as follows:

- Pipeline fuel consumption and lease and plant fuel consumption by Census Division (to NEMS PROPER and REPORTS)
- Natural gas wellhead prices by Oil and Gas Supply Module region (to NEMS REPORTS, Oil and Gas Supply Module, and Petroleum Market Module)
- Core and noncore natural gas prices by sector and Census Division (to NEMS PROPER and REPORTS, and NEMS demand modules)
- Fraction of retail fueling stations that sell compressed natural gas (to Transportation Sector Module)
- Dry natural gas production and supplemental gas supplies by Oil and Gas Supply Module region (NEMS REPORTS and Oil and Gas Supply Module)
- Peak/off-peak, core/ noncore natural gas prices to electric generators by NGTDM/Electricity Market Module region (to NEMS PROPER and REPORTS and Electricity Market Module)
- Coal consumed, electricity generated, and CO2 produced in the process of converting coal into pipeline quality synthetic gas in newly constructed plants (to Coal Market Module, Electricity Market Module, and NEMS PROPER)
- Dry natural gas production by PADD region (to Petroleum Market Module)
- Nonassociated dry natural gas production by NGTDM/Oil and Gas Supply Module region (to NEMS REPORTS and Oil and Gas Supply Module)
- Natural gas imports, exports, and associated prices by border crossing (to NEMS REPORTS)

Internal Reports

The NGTDM produces reports designed to assist in the analysis of NGTDM model results. These reports are controlled with a user-defined variable (NGDBGRPT), include the following information, and are written to the indicated output file:

- Primary peak and off-peak flows, shares, and maximum constraints going into each node (NGOBAL)
- Historical and forecast values historically based factors applied in the module (NGOBENCH)
- Intermediate results from the Distributor Tariff Submodule (NGODTM)
- Intermediate results from the Pipeline Tariff Submodule (NGOPTM)
- Convergence tracking and error message report (NGOERR)
- Aggregate/average historical values for most model elements (NGOHIST)
- Node and arc level prices and quantities along the network by cycle (NGOTREE)

External Reports

In addition to the reports described above, the NGTDM produces external reports to support recurring publications. These reports contain the following information:

- Natural gas end-use prices and consumption levels by end-use sector, type of service (core and noncore), and Census Division (and for the United States)
- Natural gas used to in a gas-to-liquids conversion process in Alaska
- Natural gas wellhead prices and production levels by NGTDM region (and the average for the lower 48 States), including a price for the Henry Hub
- Natural gas end-use and city gate prices and margins
- Natural gas import and export volumes and import prices by source or destination
- Pipeline fuel consumption by NGTDM region (and for the United States)
- Natural gas pipeline capacity (entering and exiting a region) by NGTDM region and by Census Division
- Natural gas flows (entering and exiting a region) by NGTDM region and Census Division
- Natural gas pipeline capacity between NGTDM regions
- Natural gas flows between NGTDM regions
- Natural gas underground storage and pipeline capacity by NGTDM region
- Unaccounted for natural gas[96]

[96]Unaccounted for natural gas is a balancing item between the amount of natural gas consumed and the amount supplied. It includes reporting discrepancies, net storage withdrawals (in historical years), and differences due to convergence tolerance levels.

Appendix A. NGTDM Model Abstract

Model Name: Natural Gas Transmission and Distribution Module

Acronym: NGTDM

Title: Natural Gas Transmission and Distribution Module

Purpose: The NGTDM is the component of the National Energy Modeling System (NEMS) that represents the mid-term natural gas market. The purpose of the NGTDM is to derive natural gas supply and end-use prices and flow patterns for movements of natural gas through the regional interstate network. The prices and flow patterns are derived by obtaining a market equilibrium across the three main components of the natural gas market: the supply component, the demand component, and the transmission and distribution network that links them.

Status: ACTIVE

Use: BASIC

Sponsor:
- Office of Energy Analysis
- Office of Petroleum, Gas, and Biofuels Analysis, EI-33
- Model Contact: Joe Benneche
- Telephone: (202) 586-6132

Documentation: Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, June 2011).

Previous Documentation: Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, June 2010).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, June 2009).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, January 2009).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, October 2007).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, August 2006).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, May 2005).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, March 2004)

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, May 2003)

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, January 2002).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, January 2001).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, January 2000).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, February 1999).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National*

Energy Modeling System (NEMS), DOE/EIA-M062/1 (Washington, DC, December 1997).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062/1 (Washington, DC, December 1996).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062/1 (Washington, DC, December 1995).

Energy Information Administration, *Model Documentation, Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System, Volume II: Model Developer's Report*, DOE/EIA-M062/2 (Washington, DC, January 1995).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062/1 (Washington, DC, February 1995).

Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062/1 (Washington, DC, February 1994).

Reviews Conducted:

Paul R. Carpenter, PhD, The Brattle Group. "Draft Review of Final Design Proposal Seasonal/North American Natural Gas Transmission Model." Cambridge, MA, August 15, 1996.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Natural Gas Annual Flow Module (AFM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, Aug 25, 1992.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Capacity Expansion Module (CEM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, Apr 30, 1993.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Pipeline Tariff Module (PTM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, Apr 30, 1993.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Distributor Tariff Module (DTM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, Apr 30, 1993.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Final Review of the National Energy Modeling System (NEMS) Natural Gas Transmission and Distribution Model (NGTDM)." Boston, MA, Jan 4, 1995.

Archival: The NGTDM is archived as a component of the NEMS on compact disc storage compatible with the PC multiprocessor computing platform upon completion of the NEMS production runs to generate the *Annual Energy Outlook 2011*, DOE/EIA-0383(2011). The archive package can be downloaded from ftp://ftp.eia.doe.gov/pub/forecasts/aeo.

Energy System Covered: The NGTDM models the U.S. natural gas transmission and distribution network that links the suppliers (including importers) and consumers of natural gas, and in so doing determines the regional market clearing natural gas end-use and supply (including border) prices.

Coverage: Geographic: Demand regions are the 12 NGTDM regions, which are based on the nine Census Divisions with Census Division 5 split further into South Atlantic and Florida, Census Division 8 split further into Mountain and Arizona/New Mexico, and Census Division 9 split further into California and Pacific with Alaska and Hawaii handled separately. Production is represented in the lower 48 at 17 onshore and 3 offshore regions. Import/export border crossings include three at the Mexican border, seven at the Canadian border, and 12 liquefied natural gas import terminals. In a separate component, potential liquefied natural gas production and liquefaction for U.S. import is represented for 14 international ports. A simplified Canadian representation is subdivided into an eastern and western region, with potential LNG import facilities on both shores. Consumption, production, and LNG imports to serve the Mexico gas market are largely assumption based and serve to set the level of exports to Mexico from the United States.

Time Unit/Frequency: Annually through 2035, including a peak (December through March) and off-peak forecast.

Product(s): Natural gas

Economic Sector(s): Residential, commercial, industrial, electric generators and transportation

Data Input Sources:

(Non-DOE)

- The Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU), Section 1113.
  —Federal vehicle natural gas (VNG) taxes

- Canadian Association of Petroleum Producers Statistical Handbook
  — Historical Canadian supply and consumption data
- Mineral Management Service.
  — Revenues and volumes for offshore production in Texas, California, and Louisiana
- Foster Pipeline and Storage Financial Cost Data
  — pipeline and storage financial data
- Data Resources Inc., U.S. Quarterly Model
  — Various macroeconomic data
- *Oil and Gas Journal*, "Pipeline Economics"
  — Pipeline annual capitalization and operating revenues
- Board of Governors of the Federal Reserve System Statistical Release, "Selected Interest Rates and Bond Prices"
  — Real average yield on 10 year U.S. government bonds
- Hart Energy Network's Motor Fuels Information Center at www.hartenergynetowrk.com/motorfuels/state/doc/glance/glnctax.htm
  —compressed natural gas vehicle taxes by state
- National Oceanic and Atmospheric Association
  —State level heating degree days
- U.S. Census
  —State level population data for heating degree day weights
- Natural Gas Week
  —Canada storage withdrawal and capacity data
- PEMEX Prospective de Gas Natural
  —Historical Mexico raw gas production by region
- Informes y Publicaciones, Anuario Estadísticas, Estadísticas Operativas, Producción de gas natural
  —Historical Mexico raw gas production by region
- Sener Prospectiva del Mercado de gas natural 2006-2015
  —Mexico LNG import projections

Data Input Sources:

(DOE) Forms and/or Publications:

- U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, DOE/EIA-0216.
  — Annual estimate of gas production for associated-dissolved and nonassociated categories by State/sub-state.
- Natural Gas Annual, DOE/EIA-0131.
  — By state -- natural gas consumption by sector, dry production, imports, exports, storage injections and withdrawals, balancing item, state transfers, number of residential customers, fraction of industrial market represented by historical prices, and wellhead, city gate, and end-use prices.
  — Supplemental supplies
- Natural Gas Monthly, DOE/EIA-0130.
  — By month and state – natural gas consumption by sector, marketed production, net storage withdrawals, end-use prices by sector, city gate prices

  - — By month – quantity and price of imports and exports by country, wellhead prices, lease and plant consumption, pipeline consumption, supplemental supplies
- State Energy Data System (SEDS).
  - — State level annual delivered natural gas prices when not available in the Natural Gas Annual.
- Electric Power Monthly, DOE/EIA-0226.
  - — Monthly volume and price paid for natural gas by electric generators
- *Annual Energy Review*, DOE/EIA-0384
  - — Gross domestic product and implicit price deflator
- EIA-846, "Manufacturing Energy Consumption Survey"
  - — Base year average annual core industrial end-use prices
- *Short-Term Energy Outlook*, DOE/EIA-0131.
  - — National natural gas projections for first two years beyond history
  - — Historical natural gas prices at the Henry Hub
- Department of Energy, *Natural Gas Imports and Exports*, Office of Fossil Energy
  - — Import and export volumes and prices by border location
- Department of Energy, Alternate Fuels & Advanced Vehicles Data Center, including *Alternate Fuel Price Report*, Office of Energy Efficiency and Renewable Energy
  - — Sample of retail prices paid for compressed natural gas for vehicles
  - — State motor fuel taxes
- EIA-191, "Underground Gas Storage Report"
  - — Used in part to develop working gas storage capacity data
- EIA-457, "Residential Energy Consumption Survey"
  - — Number of residential natural gas customers
- International Energy Outlook, DOE/EIA-0484.
  - — Projection of natural gas consumption in Canada and Mexico.
- International Energy Annual, DOE/EIA-0484.
  - — Historical natural gas data on Canada and Mexico.

Models and other:

- National Energy Modeling System (NEMS)
  - — Domestic supply and demand representations are provided interactively as inputs to the NGTDM from other NEMS models
- International Natural Gas Model (INGM)
  - — Provides information for setting LNG supply curves exogenously in the NGTDM

General Output Descriptions:

- Average natural gas end-use prices levels by sector and region
- Average natural gas production volumes and prices by region
- Average natural gas import and export volumes and prices by region and type
- Pipeline fuel consumption by region
- Lease and plant fuel consumption by region

- Lease and plant fuel consumption by region
- Flow of gas between regions by peak and off-peak period
- Pipeline capacity additions and utilization levels by arc
- Storage capacity additions by region

Related Models: NEMS (part of)

Model Features:

- Model Structure: Modular; three major components: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS).
  - — ITS Integrating submodule of the NGTDM. Simulates the natural gas price determination process by bringing together all major economic and technological factors that influence regional natural gas trade in the United States. Determines natural gas production and imports, flows and prices, pipeline capacity expansion and utilization, storage capacity expansion and utilization for a simplified network representing the interstate natural gas pipeline system
  - — PTS Develops parameters for setting tariffs in the ITM for transportation and storage services provided by interstate pipeline companies
  - — DTS Develops markups for distribution services provided by LDC's and intrastate pipeline companies.

- Modeling Technique:
  - — ITS, Heuristic algorithm, operates iteratively until supply/demand convergence is realized across the network
  - — PTS, Econometric estimation and accounting algorithm
  - — DTS, Econometric estimation
  - — Canada and Mexico supplies based on a combination of estimated equations and basic assumptions.

Model Interfaces: NEMS

Computing Environment:

- Hardware Used: Personal Computer
- Operating System: UNIX simulation
- Language/Software Used: FORTRAN
- Storage Requirement: 2,700K bytes for input data storage; 1,100K bytes for source code storage; and 17,500K bytes for compiled code storage
- Estimated Run Time: Varies from NEMS iteration and from computer processor, but rarely exceeds a quarter of a second per iteration and generally is less than 5 hundredths of a second.

Status of Evaluation Efforts:

Model developer's report entitled "Natural Gas Transmission and Distribution Model, Model Developer's Report for the National Energy Modeling System," dated November 14, 1994.

Date of Last Update: January 2011.

Appendix B. References

Alaska Department of Natural Resources, Division of Oil and Gas, *Alaska Oil and Gas Report*, November 2009.

Carpenter, Paul R., "Review of the Gas Analysis Modeling System (GAMS), Final Report of Findings and Recommendations" (Boston: Incentives Research, Inc., August 1991).

Decision Focus Incorporate, *Generalized Equilibrium Modeling: The Methodology of the SRI-GULF Energy Model* (Palo Alto, CA, May 1977).

Energy Information Administration, "Analytical Framework for a Natural Gas Transmission and Distribution Forecasting System," prepared by SAIC for the Analysis and Forecasting Branch within the Reserves and Natural Gas Division of the Office of Oil and Gas (Washington, DC, March 1991).

Energy Information Administration, Office of Integrated Analysis and Forecasting, "Component Design Report, Natural Gas Annual Flow Module for the Natural Gas Transmission and Distribution Model of the National Energy Modeling System" (Washington, DC, June 25, 1992).

Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618(98) (Washington, DC, May 1998).

Energy Information Administration, *Documentation of the Gas Analysis Modeling System*, DOE/EIA-M044(92) (Washington, DC, December 1991).

Energy Information Administration, Office of Integrated Analysis and Forecasting, "Component Design Report, Capacity Expansion Module for the Natural Gas Transmission and Distribution Model of the National Energy Modeling System" (Washington, DC, December 29, 1992).

Energy Information Administration, Office of Integrated Analysis and Forecasting, "Component Design Report, Distributor Tariff Module for the Natural Gas Transmission and Distribution Model of the National Energy Modeling System" (Washington, DC, January 11, 1993).

Energy Information Administration, Office of Integrated Analysis and Forecasting, "Component Design Report, Pipeline Tariff Module for the Natural Gas Transmission and Distribution Model of the National Energy Modeling System" (Washington, DC, December 29, 1992).

Energy Information Administration, "An Evaluation of Problem Formulations and Mathematical Programming Software for the Gas Market Model of NEMS," Prepared by SAIC for the Office of Integrated Analysis and Forecasting (Washington, DC, April 1992).

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Energy Information Administration, *Natural Gas 1992: Issues and Trends* DOE/EIA-0560(92) (Washington, DC, March 1993).

Energy Information Administration, *Natural Gas 1994: Issues and Trends* DOE/EIA-0560(94) (Washington, DC, July 1994).

Energy Information Administration, *Natural Gas 1995: Issues and Trends* DOE/EIA-0560(95) (Washington, DC, November 1995).

Energy Information Administration, *Natural Gas 1996: Issues and Trends* DOE/EIA-0560(96) (Washington, DC, December 1996).

Energy Information Administration, Office of Integrated Analysis and Forecasting, "Requirements for a National Energy Modeling System," (Working Paper) (Washington, DC, May 1992).

Forbes, Kevin, Science Applications International Corporation, "Efficiency in the Natural Gas Industry," Task 93-095 Deliverable under Contract No. DE-AC01-92-EI21944 for Natural Gas Analysis Branch of the Energy Information Administration, January 31, 1995.

Foster's Associates Inc., *Foster financial report of 28 Major Interstate Natural Gas Pipelines, 1996*.

Gas Technology Institute, "Liquefied Natural Gas (LNG) Methodology Enhancements in NEMS," report submitted to Energy Information Administration, March 2003.

Interstate Natural Gas Association of America (INGAA), "Availability, Economics & Production Potential of North American Unconventional Natural Gas Supplies," November 2008, written by ICF.

National Energy Board, *Canada's Energy Future: Scenarios for Supply and Demand to 2025*, 2003

Oil and Gas Journal, "Pipeline Economics," published annually in various editions.

Woolridge, Jeffrey M., Introductory Econometrics: A Modern Approach, South-Western College Publishing, 2000.

Appendix C. NEMS Model Documentation Reports

The National Energy Modeling System is documented in a series of 15 model documentation reports, most of which are updated on an annual basis. Copies of these reports are available by contacting the National Energy Information Center, 202/586-8800.

Energy Information Administration, *National Energy Modeling System Integrating Module Documentation Report*, DOE/EIA-M057.

Energy Information Administration, *Model Documentation Report: Macroeconomic Activity Module of the National Energy Modeling System*.

Energy Information Administration, *Documentation of the D.R.I. Model of the U.S. Economy*.

Energy Information Administration, *National Energy Modeling System International Energy Model Documentation Report*.

Energy Information Administration, *World Oil Refining, Logistics, and Demand Model Documentation Report*.

Energy Information Administration, *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation Report: Transportation Sector Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Documentation of the Electricity Market Module*.

Energy Information Administration, *Documentation of the Oil and Gas Supply Module*.

Energy Information Administration, *EIA Model Documentation: Petroleum Market Module of the National Energy Modeling System*.

Energy Information Administration, *Model Documentation: Coal Market Module*.

Energy Information Administration, *Model Documentation Report: Renewable Fuels Module*.

Appendix D. Model Equations

This appendix presents the mapping of each equation (by equation number) in the documentation with the subroutine in the NGTDM code where the equation is used or referenced.

Chapter 2 Equations

EQ. #	**SUBROUTINE** (or FUNCTION *)
1	NGDMD_CRVF* (core), NGDMD_CRVI* (noncore)
2-19	NGSUP_PR*
20-25	NGOUT_CAN
26-39	NGCAN_FXADJ
40	NGOUT_MEX
41	NGSETLNG_INGM
42-54	NGTDM_DMDALK

Chapter 4 Equations

EQ. #	**SUBROUTINE** (or FUNCTION *)
55, 58	NGSET_NODEDMD, NGDOWN_TREE
56, 59	NGSET_NODECDMD
57, 60	NGSET_YEARCDMD
61, 62	NGDOWN_TREE
63	NGSET_INTRAFLO
64	NGSET_INTRAFLO
65	NGSHR_CALC
66	NGDOWN_TREE
67	NGSET_MAXFLO*
68-71	NGSET_MAXPCAP
72-76	NGSET_MAXFLO*
77-79	NGSET_ACTPCAP
80-81	NGSHR_MTHCHK
82-85	NGSET_SUPPR
86-87	NGSTEO_BENCHWPR
88	NGSTEO_BENCHWPR
89-90	NGSET_ARCFEE

91-94	NGUP_TREE
95	NGSET_STORPR
96-97	NGUP_TREE
98	NGCHK_CONVNG
99	NGSET_SECPR
100	NGSET_BENCH, HNGSET_CGPR
101-106	NGSET_SECPR

Chapter 5 Equations

EQ. #	**SUBROUTINE** (or FUNCTION *)
107-118	NGDTM_FORECAST_DTARF
119-120	NGDTM_FORECAST_TRNF
121-126	NGTDM_CNGBUILD

Chapter 6 Equations

EQ. #	**SUBROUTINE** (or FUNCTION *)
127-132, 136-154, 203-205	NGPREAD
133-135, 155-156	NGPIPREAD
176-194, 206, 208-221	NGPSET_PLCOS_COMPONENTS
157-166, 172, 207, 222-231, 238	NGPSET_PLINE_COSTS
167-171, 232-237, 238-243	NGPIPE_VARTAR*
251-253	NGSTREAD
244-250, 254-256, 260-287	NGPSET_STCOS_COMPONENTS
257-259	NGPST_DEVCONST
173-175, 288-292	X1NGSTR_VARTAR*
195-202	(accounting relationships, not part of code)
293-205	NGFRPIPE_TAR*

Appendix E. Model Input Variable Mapped to Data Input Files

This appendix provides a list of the FORTRAN variables, and their associated input files, that are assigned values through FORTRAN READ statements in the source code of the NGTDM. Information about all of these variables and their assigned values (including sources, derivations, units, and definitions) are provided in the indicated input files of the NGTDM. The data file names and versions used for the *AEO2011* are identified below. These files are located on the EIA NEMS-F8 NT server. Electronic copies of these input files are available as part of the NEMS2011 archive package. The archive package can be downloaded from ftp://ftp.eia.doe.gov/pub/forecasts/aeo. In addition, the files are available upon request from Joe Benneche at (202) 586-6132 or Joseph.Benneche@eia.doe.gov.

ngcan.txt	V1.68	nghismn.txt	V1.30	ngptar.txt	V1.26
ngcap.txt	V1.32	nglngdat.txt	V1.79	nguser.txt	V1.150
ngdtar.txt	V1.38	ngmap.txt	V1.7		
nghisan.txt	V1.35	ngmisc.txt	V1.155		

Variable	File
ACTPCAP	NGCAN
ACTPCAP	NGCAP
ADDYR	NGCAP
ADJ_PIP	NGPTAR
ADJ_STR	NGPTAR
ADW	NGHISAN
AFR_CMEN	NGPTAR
AFR_DDA	NGPTAR
AFR_DIT	NGPTAR
AFR_FSIT	NGPTAR
AFR_LTDN	NGPTAR
AFR_OTTAX	NGPTAR
AFR_PFEN	NGPTAR
AFR_TOM	NGPTAR
AFX_CMEN	NGPTAR
AFX_DDA	NGPTAR
AFX_DIT	NGPTAR
AFX_FSIT	NGPTAR
AFX_LTDN	NGPTAR
AFX_OTTAX	NGPTAR
AFX_PFEN	NGPTAR
AFX_TOM	NGPTAR
AK_C	NGMISC
AK_CM	NGMISC
AK_CN	NGMISC
AK_D	NGMISC
AK_E	NGMISC
AK_EM	NGMISC
AK_ENDCONS_N	NGMISC
AK_F	NGMISC
AK_G	NGMISC
AK_HDD	NGMISC
AK_IN	NGMISC
AK_PCTLSE	NGMISC
AK_PCTPIP	NGMISC
AK_PCTPLT	NGMISC
AK_POP	NGMISC
AK_QIND_S	NGMISC
AK_RM	NGMISC
AK_RN	NGMISC
AKPIP1	NGMISC
AKPIP2	NGMISC
AL_ADJ	NGHISAN
AL_OFFD	NGHISAN
AL_OFST	NGHISAN
AL_OFST2	NGHISAN
AL_ONSH	NGHISAN
AL_ONSH2	NGHISAN
ALB_TO_L48	NGMISC
ALNGA	NGLNGDAT
ALNGB	NGLNGDAT
ALPHA_PIPE	NGPTAR
ALPHA_STR	NGPTAR
ALPHA2_PIPE	NGPTAR
ALPHA2_STR	NGPTAR
ALPHAFAC	NGUSER

Variable	File
ANUM	NGMAP
ARC_FIXTAR	NGCAN
ARC_VARTAR	NGCAN
AVGCOST	NGPTAR
AVR_CMEN	NGPTAR
AVR_DDA	NGPTAR
AVR_DIT	NGPTAR
AVR_FSIT	NGPTAR
AVR_LTDN	NGPTAR
AVR_OTTAX	NGPTAR
AVR_PFEN	NGPTAR
AVR_TOM	NGPTAR
BA_PREM	NGMISC
BAJA_CAP	NGMISC
BAJA_FIX	NGMISC
BAJA_LAG	NGMISC
BAJA_MAX	NGMISC
BAJA_PRC	NGMISC
BAJA_STAGE	NGMISC
BAJA_STEP	NGMISC
BEQ_BLDAVG	NGMISC
BEQ_BLDHRSK	NGMISC
BEQ_OPRAVG	NGMISC
BEQ_OPRHRSK	NGMISC
BNEWCAP_2003_2004	NGPTAR
BNEWCAP_POST2004	NGPTAR
BNEWCAP_PRE2003	NGPTAR
BPPRC	NGCAN
BPPRCGR	NGCAN
CAN_XMAPCN	NGMAP
CAN_XMAPUS	NGMAP
CANEXP	NGCAN
CM_ADJ	NGDTAR
CM_ALP	NGDTAR
CM_LNQ	NGDTAR
CM_PKALP	NGDTAR
CM_RHO	NGDTAR
CN_DMD	NGCAN
CN_FIXSHR	NGCAN
CN_FIXSUP	NGCAN
CN_OILSND	NGCAN
CN_UNPRC	NGCAN
CN_WOP	NGCAN
CNCAPSW	NGUSER
CNG_BUILDCOST	NGDTAR
CNG_HRZ	NGDTAR
CNG_MARKUP	NGDTAR
CNG_RETAIL_MARKUP	NGDTAR
CNG_WACC	NGDTAR
CNPER_YROPEN	NGCAP
CNPLANYR	NGCAN
CON	NGHISMN
CON_ELCD	NGHISMN
CON_EPMGR	NGHISMN
CONNOL_ELAS	NGCAN

Variable	File	Variable	File
CTG_BASCGG	NGMISC	D_DIT	NGPTAR
CTG_BASCGGCO2	NGMISC	D_FLO	NGPTAR
CTG_BASCGS	NGMISC	D_FSIT	NGPTAR
CTG_BASCGSCO2	NGMISC	D_GCMES	NGPTAR
CTG_BASCOL	NGMISC	D_GLTDS	NGPTAR
CTG_BASHHV	NGMISC	D_GPFES	NGPTAR
CTG_BASSIZ	NGMISC	D_GPIS	NGPTAR
CTG_BCLTON	NGMISC	D_GPIS	NGPTAR
CTG_BLDX	NGMISC	D_LTDN	NGPTAR
CTG_BLDX	NGMISC	D_LTDR	NGPTAR
CTG_BLDYRS	NGMISC	D_LTDR	NGPTAR
CTG_CAPYR$	NGMISC	D_LTDS	NGPTAR
CTG_CO2	NGMISC	DMAP	NGMAP
CTG_DCLCAPCST	NGMISC	D_MXPKFLO	NGPTAR
CTG_DCLOPRCST	NGMISC	D_NPIS	NGPTAR
CTG_FSTYR	NGMISC	D_NPIS	NGPTAR
CTG_IINDX	NGMISC	D_OTTAX	NGPTAR
CTG_INCBLD	NGMISC	D_OTTAX	NGPTAR
CTG_INVLOC	NGMISC	D_PFEN	NGPTAR
CTG_NAM	NGMISC	D_PFER	NGPTAR
CTG_NCL	NGMISC	D_PFER	NGPTAR
CTG_OH_LCFAC	NGMISC	D_PFES	NGPTAR
CTG_OSBLFAC	NGMISC	D_TCAP	NGPTAR
CTG_PCTCNTG	NGMISC	D_TOM	NGPTAR
CTG_PCTENV	NGMISC	D_TOM	NGPTAR
CTG_PCTLND	NGMISC	D_WCAP	NGPTAR
CTG_PCTSPECL	NGMISC	DDA_NEWCAP	NGPTAR
CTG_PCTWC	NGMISC	DDA_NPIS	NGPTAR
CTG_PRJLIFE	NGMISC	DECL_GASREQ	NGCAN
CTG_PUCAP	NGMISC	DEXP_FRMEX	NGMISC
CTG_SINVST	NGMISC	DFAC_TOMEX	NGMISC
CTG_STAFF_LCFAC	NGMISC	DFR	NGCAN
CWC_DISC	NGPTAR	DFR	NGCAN
CWC_K	NGPTAR	DMASP	NGCAN
CWC_RHO	NGPTAR	DMASP	NGCAN
CWC_TOM	NGPTAR	EL_ALP	NGDTAR
D_ADDA	NGPTAR	EL_CNST	NGDTAR
D_ADDA	NGPTAR	EL_PARM	NGDTAR
D_ADIT	NGPTAR	EL_RESID	NGDTAR
D_ADIT	NGPTAR	EL_RHO	NGDTAR
D_APRB	NGPTAR	ELE_GFAC	NGMISC
D_APRB	NGPTAR	EMMSUB_EL	NGMAP
D_CMEN	NGPTAR	EMMSUB_NG	NGMAP
D_CMER	NGPTAR	EMRP_BLDAVG	NGMISC
D_CMER	NGPTAR	EMRP_BLDHRSK	NGMISC
D_CMES	NGPTAR	EMRP_OPRAVG	NGMISC
D_CONST	NGPTAR	EMRP_OPRHRSK	NGMISC
D_CONST	NGPTAR	EQUITY_BLDAVG	NGMISC
D_CONST	NGPTAR	EQUITY_BLDHRSK	NGMISC
D_CONST	NGPTAR	EQUITY_OPRAVG	NGMISC
D_CWC	NGPTAR	EQUITY_OPRHRSK	NGMISC
D_CWC	NGPTAR	EXP_A	NGPTAR
D_DDA	NGPTAR	EXP_B	NGPTAR
D_DDA	NGPTAR	EXP_C	NGPTAR
D_DIT	NGPTAR	EXP_FRMEX	NGMISC

Variable	File	Variable	File
FDGOM	NGHISMN	HELE_SHR	NGMISC
FDIFF	NGDTAR	HFAC_GPIS	NGPTAR
FE_CCOST	NGMISC	HFAC_REV	NGPTAR
FE_EXPFAC	NGMISC	HHDD	NGDTAR
FE_FR_TOM	NGMISC	HI_RN	NGMISC
FE_PFUEL_FAC	NGMISC	HIND_SHR	NGMISC
FE_R_STTOM	NGMISC	HISTRESCAN	NGCAN
FE_R_TOM	NGMISC	HISTWELCAN	NGCAN
FE_STCCOST	NGMISC	HNETINJ	NGCAN
FE_STEXPFAC	NGMISC	HNETWTH	NGCAN
FEDTAX_RT	NGMISC	HNETWTH	NGHISMN
FIXLNGFLG	NGMAP	HPEMEX_SHR	NGMISC
FLO_THRU_IN	NGCAN	HPIMP	NGHISAN
FMASP	NGCAN	HPKSHR_FLOW	NGMISC
FMASP	NGCAN	HPKUTZ	NGCAP
FR_AVGTARYR	NGMISC	HPRC	NGHISMN
FR_BETA	NGMISC	HPSUP	NGCAN
FR_CAPITL0	NGMISC	HQIMP	NGHISAN
FR_CAPYR	NGMISC	HQSUP	NGCAN
FR_DEBTRATIO	NGMISC	HQTY	NGHISMN
FR_DISCRT	NGMISC	HRC_SHR	NGMISC
FR_ESTNYR	NGMISC	HW_ADJ	NGDTAR
FR_OTXR	NGMISC	HW_BETA0	NGDTAR
FR_PADDTAR	NGMISC	HW_BETA1	NGDTAR
FR_PCNSYR	NGMISC	HW_RHO	NGDTAR
FR_PDRPFAC	NGMISC	HYEAR	NGHISAN
FR_PEXPFAC	NGMISC	ICNBYR	NGCAN
FR_PFUEL	NGMISC	IEA_CON	NGMISC
FR_PMINWPR	NGMISC	IEA_PRD	NGMISC
FR_PMINYR	NGMISC	IMASP	NGCAN
FR_PPLNYR	NGMISC	IMASP	NGCAN
FR_PRISK	NGMISC	IMP_TOMEX	NGMISC
FR_PTREAT	NGMISC	IN_ALP	NGDTAR
FR_PVOL	NGMISC	IN_CNST	NGDTAR
FR_ROR_PREM	NGMISC	IN_DIST	NGDTAR
FR_TOM0	NGMISC	IN_LNQ	NGDTAR
FR_TXR	NGMISC	IN_PKALP	NGDTAR
FRATE	NGPTAR	IN_RHO	NGDTAR
FREE_YRS	NGDTAR	IND_GFAC	NGMISC
FRMETH	NGCAN	INFL_RT	NGMISC
FSRGN	NGMAP	INIT_GASREQ	NGCAN
FSTYR_GOM	NGHISAN	INS_FAC	NGMISC
FTAX	NGDTAR	INTRAREG_TAR	NGDTAR
FUTWTS	NGMISC	INTRAST_TAR	NGDTAR
GAMMAFAC	NGUSER	IPR	NGCAN
GDP_B87	NGMISC	IRES	NGCAN
GOF_AL	NGHISAN	IRG	NGCAN
GOF_CA	NGHISAN	IRIGA	NGCAN
GOF_LA	NGHISAN	IRIGA	NGCAN
GOF_TX	NGHISAN	JNETWTH	NGHISMN
HAFLOW	NGMISC	LA_OFFD	NGHISAN
HCG_BENCH	NGDTAR	LA_OFST	NGHISAN
HCGPR	NGHISAN	LA_ONSH	NGHISAN
HCUMSUCWEL	NGCAN	LABORLOC	NGMISC
HDYWHTLAG	NGDTAR	LEVELYRS	NGPTAR

Variable	File	Variable	File
LNG_XMAP	NGMAP	NGDBGRPT	NGUSER
LNGA	NGLNGDAT	NIND_SHR	NGMISC
LNGB	NGLNGDAT	NINJ_TOT	NGHISMN
LNGCAP	NGLNGDAT	NLNGA	NGLNGDAT
LNGCRVOPT	NGLNGDAT	NLNGB	NGLNGDAT
LNGDATA	NGMISC	NLNGPTS	NGLNGDAT
LNGDIF_GULF	NGLNGDAT	NNETWITH	NGUSER
LNGDIFF	NGMISC	NOBLDYR	NGUSER
LNGFIX	NGLNGDAT	NODE_ANGTS	NGMAP
LNGMIN	NGLNGDAT	NODE_SNGCOAL	NGMAP
LNGPPT	NGLNGDAT	NONU_ELAS_F	NGDTAR
LNGPS	NGLNGDAT	NONU_ELAS_I	NGDTAR
LNGQPT	NGLNGDAT	NPEMEX_SHR	NGMISC
LNGQS	NGLNGDAT	NPROC	NGMAP
LNGTAR	NGLNGDAT	NQPF_TOT	NGHISMN
LSTYR_MMS	NGHISAN	NRC_SHR	NGMISC
MAINT_FAC	NGMISC	NRCI_INV	NGMISC
MAP_NG	NGMAP	NRCI_LABOR	NGMISC
MAP_NRG_CRG	NGDTAR	NRCI_OPER	NGMISC
MAP_OG	NGMAP	NSRGN	NGMAP
MAP_PRDST	NGHISMN	NSTAT	NGDTAR
MAP_STSUB	NGHISAN	NSTSTOR	NGHISMN
MAPLNG_NEW	NGMAP	NSUPLM_TOT	NGHISMN
MAPLNG_NG	NGMAP	NUM_REGSHR	NGDTAR
MAX_CNG_BUILD	NGDTAR	NUMRS	NGDTAR
MAXCYCLE	NGUSER	NWTH_TOT	NGHISMN
MAXPLNG	NGLNGDAT	NYR_MISS	NGHISAN
MAXPRRFAC	NGMISC	OCSMAP	NGMAP
MAXPRRNG	NGMISC	oEL_MRKUP_BETA	NGDTAR
MAXUTZ	NGCAP	oEL_MRKUP_BETA	NGDTAR
MBAJA	NGMISC	OEQGCELGR	NGMISC
MDPIP1	NGMISC	OEQGFELGR	NGMISC
MDPIP2	NGMISC	OEQGIELGR	NGMISC
MEX_XMAP	NGMAP	OF_LAST	NGHISAN
MEX_XMAP	NGMAP	OOGHHPRNG	NGMISC
MEXEXP_SHR	NGMISC	OOGQNGEXP	NGMISC
MEXIMP_SHR	NGMISC	OPPK	NGCAP
MEXLNG	NGMISC	OPTCOM	NGDTAR
MEXLNGMIN	NGLNGDAT	OPTELO	NGDTAR
MISC_GAS	NGHISAN	OPTELP	NGDTAR
MISC_OIL	NGHISAN	OPTIND	NGDTAR
MISC_ST	NGHISAN	OPTRES	NGDTAR
MON_PEXP	NGHISMN	OQGCELGR	NGMISC
MON_PIMP	NGHISMN	OQGFEL	NGMISC
MON_QEXP	NGHISMN	OQGFELGR	NGMISC
MON_QIMP	NGHISMN	OQGIEL	NGMISC
MONMKT_PRD	NGHISMN	OQGIELGR	NGMISC
MSPLIT_STSUB	NGHISAN	OQNGEL	NGMISC
MUFAC	NGUSER	OSQGFELGR	NGMISC
NAW	NGHISAN	OSQGIELGR	NGMISC
NCNMX	NGCAN	OTH_FAC	NGMISC
NELE_SHR	NGMISC	PARM_LNGCRV3	NGLNGDAT
NG_CENMAP	NGMAP	PARM_LNGCRV5	NGLNGDAT
NGCFEL	NGHISMN	PARM_LNGELAS	NGLNGDAT
NGDBGCNTL	NGUSER	PARM_MINPR	NGUSER

Variable	File	Variable	File
PARM_SUPCRV3	NGUSER	QOF_GM	NGHISAN
PARM_SUPCRV5	NGUSER	QOF_LA	NGHISAN
PARM_SUPELAS	NGUSER	QOF_LAFD	NGHISAN
PCLADJ	NGMISC	QOF_MS	NGHISAN
PCNT_R	NGPTAR	QOF_TX	NGHISAN
PCT_AL	NGHISAN	QSUP_DELTA	NGUSER
PCT_LA	NGHISAN	QSUP_SMALL	NGUSER
PCT_MS	NGHISAN	QSUP_WT	NGUSER
PCT_TX	NGHISAN	RC_GFAC	NGMISC
PCTADJSHR	NGUSER	RECS_ALIGN	NGDTAR
PCTFLO	NGUSER	RESBASE	NGCAN
PEAK	NGCAP	RESBASYR	NGCAN
PEMEX_GFAC	NGMISC	RESTECH	NGCAN
PEMEX_PRD	NGMISC	RETAIL_COST	NGDTAR
PER_YROPEN	NGCAP	REV	NGHISMN
PERFDTX	NGHISAN	RGRWTH	NGCAN
PERMG	NGDTAR	RGRWTH	NGCAN
PIPE_FACTOR	NGPTAR	ROF_AL	NGHISAN
PKOPMON	NGMISC	ROF_CA	NGHISAN
PKSHR_CDMD	NGCAN	ROF_GM	NGHISAN
PKSHR_PROD	NGCAN	ROF_LA	NGHISAN
PLANPCAP	NGCAP	ROF_MS	NGHISAN
PLANPCAP	NGCAP	ROF_TX	NGHISAN
PMMMAP_NG	NGMAP	RS_ADJ	NGDTAR
PNGIMP	NGLNGDAT	RS_ALP	NGDTAR
PRAT	NGCAN	RS_COST	NGDTAR
PRAT	NGCAN	RS_LNQ	NGDTAR
PRC_EPMCD	NGHISMN	RS_PARM	NGDTAR
PRC_EPMGR	NGHISMN	RS_PKALP	NGDTAR
PRCWTS	NGMISC	RS_RHO	NGDTAR
PRCWTS2	NGMISC	SCEN_DIV	NGHISAN
PRD_GFAC	NGMISC	SCH_ID	NGHISAN
PRD_MLHIS	NGHISMN	SELE_SHR	NGMISC
PRICE_AL	NGHISAN	SHR_OPT	NGUSER
PRICE_CA	NGHISAN	SIM_EX	NGHISAN
PRICE_LA	NGHISAN	SIND_SHR	NGMISC
PRICE_TX	NGHISAN	SITM_RG	NGHISAN
PRJSDECOM	NGMISC	SNG_EM	NGHISAN
PRMETH	NGCAN	SNG_OG	NGHISAN
PROC_ORD	NGMAP	SNGCOAL	NGHISAN
PSUP_DELTA	NGUSER	SNGCOAL	NGMISC
PTCURPCAP	NGCAP	SNGLIQ	NGHISAN
PTMAXPCAP	NGCAN	SPCNEWFAC	NGPTAR
PTMBYR	NGPTAR	SPCNODID	NGPTAR
PTMSTBYR	NGPTAR	SPCNODID	NGPTAR
PUTL_POW	NGHISAN	SPCNODN	NGPTAR
Q23TO3	NGCAN	SPCPNODBAS	NGPTAR
QAK_ALB	NGMISC	SPEMEX_SHR	NGMISC
QLP_LHIS	NGHISMN	SPIN_PER	NGHISAN
QMD_ALB	NGMISC	SRATE	NGPTAR
QNGIMP	NGLNGDAT	SRC_SHR	NGMISC
QOF_AL	NGHISAN	STADIT_ADIT	NGPTAR
QOF_ALFD	NGHISAN	STADIT_C	NGPTAR
QOF_ALST	NGHISAN	STADIT_NEWCAP	NGPTAR
QOF_CA	NGHISAN	STAX	NGDTAR

Variable	File	Variable	File
STCCOST_BETAREG	NGPTAR	STSTATE	NGHISMN
STCCOST_CREG	NGPTAR	STTAX_RT	NGMISC
STCWC_CREG	NGPTAR	STTOM_C	NGPTAR
STCWC_RHO	NGPTAR	STTOM_RHO	NGPTAR
STCWC_TOTCAP	NGPTAR	STTOM_WORKCAP	NGPTAR
STDDA_CREG	NGPTAR	STTOM_YR	NGPTAR
STDDA_NEWCAP	NGPTAR	SUPARRAY	NGMAP
STDDA_NPIS	NGPTAR	SUPCRV	NGUSER
STDISCR	NGUSER	SUPREG	NGMAP
STENDCON	NGUSER	SUPSUB_NG	NGMAP
STEOYRS	NGUSER	SUPSUB_OG	NGMAP
STEP_CN	NGCAN	SUPTYPE	NGMAP
STEP_MX	NGCAN	SUTZ	NGCAP
STLNGIMP	NGUSER	SUTZ	NGCAP
STLNGRG	NGUSER	TAX_FAC	NGMISC
STLNGRGN	NGUSER	TFD	NGDTAR
STLNGYR	NGUSER	TFDYR	NGDTAR
STLNGYRN	NGUSER	TOM_BYEAR	NGPTAR
STOGPRSUP	NGUSER	TOM_BYEAR_EIA	NGPTAR
STOGWPRNG	NGUSER	TOM_DEPSHR	NGPTAR
STPHAS_YR	NGUSER	TOM_GPIS1	NGPTAR
STPIN_FLG	NGUSER	TOM_K	NGPTAR
STPNGCM	NGUSER	TOM_RHO	NGPTAR
STPNGEL	NGUSER	TOM_YR	NGPTAR
STPNGIN	NGUSER	TRN_DECL	NGDTAR
STPNGRS	NGUSER	TTRNCAN	NGCAN
STQGPTR	NGUSER	URES	NGCAN
STQLPIN	NGUSER	URES	NGCAN
STR_EFF	NGPTAR	URG	NGCAN
STR_FACTOR	NGPTAR	URG	NGCAN
STRATIO	NGPTAR	UTIL_ELAS_F	NGDTAR
STSCAL_CAN	NGUSER	UTIL_ELAS_I	NGDTAR
STSCAL_DISCR	NGUSER	WHP_LHIS	NGHISMN
STSCAL_FPR	NGUSER	WLMETH	NGCAN
STSCAL_IPR	NGUSER	WPR4CAST_FLG	NGUSER
STSCAL_LPLT	NGUSER	XBLD	NGCAP
STSCAL_NETSTR	NGUSER	XBM_ISBL	NGMISC
STSCAL_PFUEL	NGUSER	XBM_LABOR	NGMISC
STSCAL_SUPLM	NGUSER	YDCL_GASREQ	NGCAN
STSCAL_WPR	NGUSER		

Appendix F. Derived Data

Table F1

Data: Parameter estimates for the Alaskan natural gas consumption equations for the residential and commercial sectors and the Alaskan natural gas wellhead price.

Author: Tony Radich, EIA, June 2007, reestimated by Margaret Leddy, EIA, July 2009

Source: *Natural Gas Annual*, DOE/EIA-0131.

Derivation: Annual data from 1974 through 2008 were transformed into logarithmic form, tested for unit roots, and examined for simple correlations. When originally estimated, heating degree day quantity was calculated using a five-year average, but was statistically insignificant in both the residential and commercial cases and dropped from the final estimations. Lags of dependent variables were added as needed to remove serial correlation from residuals. Heteroskedasticity-consistent standard error estimators were also used as needed.

Residential Natural Gas Consumption

The forecast equation for residential natural gas consumption is estimated below:

$$LN_CONS_RES = (\beta_0*(1-\beta_{-1}) + (\beta_1*(1-\beta_{-1})*LN_RES_CUST) + (\beta_{-1}*(LN_CONS_RES(-1)*1000)))/1000.$$

where,

LN_CONS_RES	=	natural log of Alaska residential natural gas consumption in MMcf
LN_RES_CUST	=	natural log of thousands of Alaska residential gas customers. See the forecast equation for Alaska residential gas customers in Table F2.
(-1)	=	first lag

All variables are annual from 1974 through 2008.

Regression Diagnostics and Parameters Estimates:

Dependent Variable: LN_CONS_RES
Method: Least Squares
Date: 07/03/07
Sample (adjusted): 1974 – 2008
Included observations: 35 after adjustments
Newey-West HAC Standard Errors & Covariance (lag truncation=3)

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
C	6.983794	0.608314	11.48058	0.0000	β_0
LN_RES_CUST	0.601932	0.136919	4.396257	0.0001	β_1
AR(-1)	0.364042	0.117856	3.088872	0.0041	β_{-1}

R-squared	0.788754	Mean dependent var	9.486861
Adjusted R-squared	0.775552	S.D. dependent var	0.329138
S.E. of regression	0.155932	Akaike info criterion	-0.79697
Sum squared resid	0.778077	Schwarz criterion	-0.66366
Log likelihood	16.94702	Hannan-Quinn criter.	-0.75095
F-statistic	59.74123	Durbin-Watson stat	1.957789
Prob(F-statistic)	0.00000		

The equation for the Alaska residential natural gas consumption translates into the following forecast equation in the code:

AKQTY_F(1) = (exp(6.983794 * (1 - 0.364042)) * (AK_RN(t))**(0.601932 * (1 - 0.364042)) * (PREV_AKQTY(1,t-1)*1000)** (0.364042))/1000.

where,

AKQTY_F(1) = residential Alaskan natural gas consumption, (Bcf)
PREV_AKQTY(1,t-1) = previous year's residential Alaskan natural gas consumption, (Bcf)
AK_RN(t) = residential consumers (thousands) at current year. See Table F2

Commercial Natural Gas Consumption

The forecast equation for commercial natural gas consumption is estimated below:

LN_CONS_COM = $(\beta_0*(1 - \beta_{-1}) + (\beta_1*$LN_COM_CUST) + $(-\beta_{-1}* \beta_1)*$LN_COM_CUST(-1) + $(\beta_{-1}*$ LN_CONS_COM(-1)*1000))/1000.

where,

LN_CONS_COM = natural log of Alaska commercial natural gas consumption in MMcf
LN_COM_CUST = natural log of thousands of Alaska commercial gas customers. See the forecast equation in Table F2.
(-1) = first lag

All variables are annual from 1974 through 2008.

Regression Diagnostics and Parameters Estimates:

Dependent Variable: LN_CONS_COM
Method: Least Squares
Date: 07/22/09 Time: 09:36
Sample (adjusted): 1974 2008
Included observations: 35 after adjustments
Convergence achieved after 9 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=3)

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
C	9.425307	0.229458	41.07648	0.0000	β_0
LN_COM_CUST	0.205020	0.115140	1.780615	0.0845	β_1
AR(1)	0.736334	0.092185	7.987556	0.0000	β_{-1}

R-squared	0.696834	Mean dependent var	9.885287
Adjusted R-squared	0.677886	S.D. dependent var	0.213360
S.E. of regression	0.121093	Akaike info criterion	-1.302700
Sum squared resid	0.469232	Schwarz criterion	-1.169385
Log likelihood	25.79725	Hannan-Quinn criter.	-1.256680
F-statistic	36.77630	Durbin-Watson stat	1.680652
Prob(F-statistic)	0.000000		

The equation in the code for the Alaska commercial natural gas consumption follows:

```
AKQTY_F(2) = (exp(9.425307 * (1 - 0.736334)) * (AK_CN(t)**(0.205020)) *
             (AK_CN(t-1)**(-0.736334 * 0.205020)) *
             (PREV_AKQTY(2,t-1)*1000.)**(0.736334)))/1000.
```

where,

AKQTY_F(2) = commercial Alaskan natural gas consumption, (Bcf)
PREV_AKQTY(2,t-1) = previous year's commercial Alaskan natural gas consumption, (Bcf)
AK_CN(t) = commercial consumers (thousands) at current year. See Table F2

Natural Gas Wellhead Price

The forecast equation for natural gas wellhead price is determined below:

$$\ln AK_WPRC_t = \beta_{-1} * \ln AK_WPRC_{t-1} + \beta_1 * (1 - \beta_{-1}) * \ln IRAC87$$

Dependent Variable: LN_WELLHEAD_PRICE
Method: Least Squares
Date: 07/22/09 Time: 13:25
Sample (adjusted): 1974 2008
Included observations: 35 after adjustments
Convergence achieved after 6 iterations

	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
LN_IRAC87	0.280760	0.101743	2.759499	0.0094	β_1
AR(1)	0.934077	0.040455	23.08940	0.0000	β_{-1}

R-squared	0.881227	Mean dependent var	0.135244
Adjusted R-squared	0.877628	S.D. dependent var	0.540629
S.E. of regression	0.189122	Akaike info criterion	-0.437408
Sum squared resid	1.180310	Schwarz criterion	-0.348531
Log likelihood	9.654637	Hannan-Quinn criter.	-0.406727
Durbin-Watson stat	2.121742		

Inverted AR Roots .93

The forecast equation becomes:

$$AK_WPRC_t = AK_WPRC_{t-1}^{0.934077} * oIT_WOP_{y,1}^{(0.280760*(1-0.934077))}$$

where,

AK_WPRC_t = average natural gas wellhead price (1987$/Mcf) in year t.

AK_F = Parameters for Alaskan natural gas wellhead price (Appendix E).

$oIT_WOP_{y,1}$ or IRAC87 = World oil price (International Refinery Acquisition Cost) (1987$/barrel)

t = year index

Data used in estimating parameters in Tables F1 and F2

	(mmcf) Res_Cons	(mmcf) Com_Con	1987$/Mcf Res_Price	1987$/Mcf Com_Price	1987$/Mcf Wellhead Price	Thousand Population	HDD, Alaska	Thousand Res_ Cust	Thousand Com_ Cust	(2000=1) GDP defl	87$/bbl IRAC	Mbbl oil_prod
1973	5024	12277	3.61	1.79	0.34	336.4	12865	23	3	0.3185	9.38	
1974	4163	13106	3.33	1.83	0.36	348.1	12655	22	4	0.3473	26.39	
1975	10393	14415	3.14	1.87	0.58	384.1	12391	25	4	0.38	26.83	
1976	10917	14191	3	1.89	0.71	409.8	11930	28	4	0.402	24.55	
1977	11282	14564	2.93	2.29	0.68	418	12521	30	5	0.4275	24.88	
1978	12166	15208	2.82	2.11	0.83	411.6	11400	33	5	0.4576	23.31	
1979	7313	15862	2.53	1.52	0.77	413.7	11149	36	6	0.4955	32.01	
1980	7917	16513	2.34	1.44	0.99	419.8	10765	37	6	0.5404	45.9	
1981	7904	16149	2.41	1.73	0.77	434.3	11248	40	6	0.5912	45.87	587337
1982	10554	24232	2.09	1.86	0.74	464.3	11669	48	7	0.6273	39.15	618910
1983	10434	24693	2.62	2.18	0.82	499.1	10587	55	8	0.6521	32.89	625527
1984	11833	24654	2.69	2.24	0.79	524	12161	63	10	0.6766	31.25	630401
1985	13256	20344	2.95	2.48	0.78	543.9	11237	65	10	0.6971	28.34	666233
1986	12091	20874	3.34	2.6	0.51	550.7	11398	66	11	0.7125	14.38	681310
1987	12256	20224	3.21	2.41	0.94	541.3	11704	67.648	11.484	0.732	18.13	715955
1988	12529	20842	3.35	2.51	1.23	535	11116	68.612	11.649	0.7569	14.08	738143
1989	13589	21738	3.38	2.39	1.27	538.9	10884	69.54	11.806	0.7856	16.85	683979
1990	14165	21622	3.4	2.36	1.24	553.17	11101	70.808	11.921	0.8159	19.52	647309
1991	13562	20897	3.62	2.51	1.28	569.05	11582	72.565	12.071	0.8444	16.21	656349
1992	14350	21299	3.21	2.24	1.19	586.72	11846	74.268	12.204	0.8639	15.42	627322
1993	13858	20003	3.28	2.3	1.18	596.91	11281	75.842	12.359	0.8838	13.37	577495
1994	14895	20698	2.92	2.01	1.03	600.62	11902	77.67	12.475	0.9026	12.58	568951
1995	15231	24979	2.88	1.8	1.3	601.58	10427	79.474	12.584	0.9211	13.62	541654
1996	16179	27315	2.67	1.81	1.26	605.21	11498	81.348	12.732	0.9385	16.1	509999
1997	15146	26908	2.89	1.87	1.4	609.66	11165	83.596	12.945	0.9541	14.22	472949
1998	15617	27079	2.78	1.83	1	617.08	11078	86.243	13.176	0.9647	9.14	428850
1999	17634	27667	2.72	1.63	1.02	622	12227	88.924	13.409	0.9787	12.91	383199
2000	15987	26485	2.62	1.51	1.29	627.53	10908	91.297	13.711	1	20.28	355199
2001	16818	15849	3.02	2.26	1.42	632.24	12227	93.896	14.002	1.024	15.73	351411
2002	16191	15691	3.1	2.4	1.5	640.54	10908	97.077	14.342	1.0419	16.66	359335
2003	16853	17270	3.02	2.46	1.66	647.75	10174	100.4	14.502	1.064	19.06	355582
2004	18200	18373	3.26	2.77	2.29	656.83	10296	104.36	13.999	1.0946	24.01	332465
2005	18029	16903	3.71	3.19	3.08	663.25	10103	108.4	14.12	1.13	31.65	315420
2006	20616	18544	4.29	2.98	3.64	670.05	11269	112.27	14.384	1.1657	37.06	270486
2007	19843	18756	5.31	4.63	3.44	668.74	10815	115.5	13.408	1.1966	41.01	263595
2008	21440	18717.5	5.21	4.73	3.88	671.31	11640	118	13	1.225	55.44	249874

Table F2

Data: Equations for the number of residential and commercial customers in Alaska

Author: Tony Radich, EIA, June, 2007 and Margaret Leddy, July 2009.

Source: *Natural Gas Annual* (1985-2000), DOE/EIA-0131, see Table F1.

Derivation:

a. Residential customers

Since 1967, the number of residential households has increased steadily, mirroring the population growth in Alaska. Because the current year's population is highly dependent on the previous year's value, the number of residential consumers was estimated based on its lag values. The forecast equation is determined as follows:

$$NRS_t = \beta_0 + \beta_{-1} * NRS_{t-1} + \beta_{-2} * NRS_{t-2} + \beta_1 * POP$$

where,

NRS = natural log of thousands of Alaska residential gas customers (AK_RN in code)
POP = natural log of Alaska population in thousands (AK_POP in code, Appendix E)
t = year

Regression Diagnostics and Parameters Estimates:

Dependent Variable: NRS
Method: Least Squares
Date: 07/03/07
Sample (adjusted): 1969-2005
Included observations: 37 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
C	-2.677338	0.946058	-2.829994	0.0079	β_0
NRS(-1)	0.887724	0.166407	5.334659	0.0000	β_{-1}
NRS(-2)	-0.184504	0.141213	-1.306569	0.2004	β_{-2}
POP	0.626436	0.201686	3.105990	0.0039	β_1

R-squared	0.995802	Mean dependent var	3.950822
Adjusted R-squared	0.995421	S.D. dependent var	0.602330
S.E. of regression	0.040760	Akaike info criterion	-3.460402
Sum squared resid	0.054827	Schwarz criterion	-3.286248
Log likelihood	68.01743	F-statistic	2609.424
Durbin-Watson stat	1.656152	Prob(F-statistic)	0.000000

This translates into the following forecast equation in the code:

$$AK_RN_t = \exp[-2.677 + (0.888*\log(AK_RN_{t-1})) - (0.185*\log(AK_RN_{t-2})) + (0.626*\log(AK_POP_t))]$$

b. Commercial customers

The number of commercial consumers, based on billing units, also showed a strong relationship to its lag value. The forecast equation was determined using data from 1985 to 2008 as follows:

$$COM_CUST_t = \beta 0 + \beta_{-1} * COM_CUST_{t-1}$$

where,

COM_CUST = number of Alaska commercial gas customers in year t, in thousands(AK_CM in the code)

t = year

Regression Diagnostics and Parameters Estimates:

Dependent Variable: COM_CUST
Method: Least Squares
07/14/09
Sample (adjusted): 1974-2008
Included observations: 35 after adjustments
Newey-West HAC Standard Errors & Covariance (lag truncation=3)

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
C	0.932946	0.294368	3.169323	0.0033	β_0
COM_CUST(-1)	0.937471	0.023830	39.33956	0.0000	β_{-1}

R-squared	0.982050	Mean dependent var	10.63666
Adjusted R-squared	0.981506	S.D. dependent var	3.534514
S.E. of regression	0.480669	Akaike info criterion	1.428171
Sum squared resid	7.624424	Schwarz criterion	1.517048
Log likelihood	-22.99300	Hannan-Quinn criter.	1.458852
F-statistic	1805.422	Durbin-Watson	1.859586
Prob(F-statistic)	0.000000		

This translates into the following forecast equation in the code:

$$AK_CN_t = 0.932946 + (0.937471 * AK_CN_{t-1})$$

Table F3

Data: Coefficients for the following Pipeline Tariff Submodule forecasting equations for pipeline and storage: total cash working capital for the combined existing and new capacity; depreciation, depletion, and amortization expenses for existing capacity; accumulated deferred income taxes for the combined existing and new capacity; and total operating and maintenance expense for the combined existing and new capacity.

Author: Science Applications International Corporation (SAIC)

Source: Foster Pipeline Financial Data, 1997-2006
Foster Storage Financial Data, 1990-1998

Variables:

For Transportation:

R_CWC	=	total pipeline transmission cash working capital for existing and new capacity (2005 real dollars)
DDA_E	=	annual depreciation, depletion, and amortization costs for existing capacity (nominal dollars)
NPIS_E	=	net plant in service for existing capacity in dollars (nominal dollars)
NEWCAP_E	=	change in existing gross plant in service (nominal dollars) between t and t-1 (set to zero during the forecast year phase since $GPIS_E_{a,t} = GPIS_E_{a,t+1}$ for year t >= 2007)
ADIT	=	accumulated deferred income taxes (nominal dollars)
NEWCAP	=	change in gross plant in service between t and t-1 (nominal dollars)
R_TOM	=	total operating and maintenance cost for existing and new capacity (2005 real dollars)
GPIS	=	capital cost of plant in service for existing and new capacity (nominal dollars)
DEPSHR	=	level of the accumulated depreciation of the plant relative to the gross plant in service for existing and new capacity at the beginning of year t. This variable is a proxy for the age of the capital stock.
TECHYEAR	=	MODYEAR (time trend in Julian units, the minimum value of this variable in the sample being 1997, otherwise TECHYEAR=0 if less than 1997)
a	=	arc
t	=	forecast year

For Storage:

R_STCWC	=	total cash working capital at the beginning of year t for existing and new capacity (1996 real dollars)
DSTTCAP	=	total gas storage capacity (Bcf)
STDDA_E	=	annual depreciation, depletion, and amortization costs for existing capacity (nominal dollars)

STNPIS_E	=	net plant in service for existing capacity (nominal dollars)
STNEWCAP	=	change in gross plant in service for existing capacity (nominal dollars)
STADIT	=	accumulated deferred income taxes (nominal dollars)
NEWCAP	=	change in gross plant in service for the combined existing and new capacity between years t and t-1 (nominal dollars)
R_STTOM	=	total operating and maintenance cost for existing and new capacity (1996 real dollars)
DSTWCAP	=	level of gas working capacity for region r during year t (Bcf)
r	=	NGTDM region
t	=	forecast year

References: For transportation: "Memorandum describing the estimated and forecast equations for TOM, DDA, CWC, and ADIT for the new PTM," by SAIC, June 23-July 22, 2008.
For storage: "Memorandum describing the estimated and forecast equations for TOM, DDA, CWC, and ADIT for the new PTM," by SAIC, May 31, 2000.

Derivation: Estimations were done by using an accounting algorithm in combination with estimation software. Projections are based on a series of econometric equations which have been estimated using the Time Series Package (TSP) software. Equations were estimated by arc for pipelines and by NGTDM region for storage, as follows: total cash working capital for the combined existing and new capacity; depreciation, depletion, and amortization expenses for existing capacity; accumulated deferred income taxes for the combined existing and new capacity; and total operating and maintenance expense for the combined existing and new capacity. These equations are defined as follows:

(1) Total Cash Working Capital for the Combined Existing and New Capacity

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model.

Because of economies in cash management, a log-linear specification between total operating and maintenance expenses, R_TOM_a, and the level of cash working capital, R_CWC_a was assumed. To control for arc specific effects, a binary variable was created for each of the arcs. The associated coefficient represents the arc specific constant term.

The underlying notion of this equation is the working capital represents funds to maintain the capital stock and is therefore driven by changes in R_TOM

The forecasting equation is presented in two stages.

Stage 1:

$$Ln(R_CWC_{a,t}) = CWC_C_a * (1-\rho) + CWC_TOM * Ln(R_TOM_{a,t}) + \rho * Ln(R_CWC_{a,t-1}) - \rho * CWC_TOM * Ln(R_TOM_{a,t-1})$$

Stage 2:

$$R_CWC_{a,t} = CWC_K * \exp(Ln(R_CWC_{a,t}))$$

where,

R_CWC	=	total pipeline transmission cash working capital for existing and new capacity (2005 real dollars)
CWC_C_a	=	estimated arc specific constant for gas transported from node to node (see Table F3.2)
CWC_TOM	=	estimated R_TOM coefficient (see Table F3.2)
R_TOM	=	total operation and maintenance expenses in 2005 real dollars
CWC_K	=	correction factor estimated in stage 2 of the regression equation estimation process
ρ	=	autocorrelation coefficient from estimation (see Table F3.2 -- CWC_RHO)

Ln is a natural logarithm operator and CWC_K is the correction factor estimated in equation two.

The results of this regression are reported below:

Dependent variable: R_CWC
Number of observations: 396

Mean of dep. var.	= 18503.0	LM het. Test	= 135.638 [.000]
Std. dev. of dep. var.	= 283454.4	Durbin-Watson	= 2.29318 [<1.00]
Sum of squared residuals	= .116124E+11	Jarque-Bera test	= 6902.15 [.000]
Variance of residuals	= .293986E+08	Ramsey's RESET2	= .849453 [.357]
Std. error of regression	= 5422.05	Schwarz B.I.C.	= 3969.29
R-squared	= .963435	Log likelihood	= -3966.30
Adjusted R-squared	= .963435		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
CWC_K	1.01813	8.31E-03	122.551	[.000]

For Storage:

$$R_STCWC_{r,t} = e^{(\beta_{0,r} * (1-\rho))} * DSTTCAP_{r,t-1}^{\beta_1} * R_STCWC_{r,t-1}^{\rho} * DSTTCAP_{r,t-2}^{-\rho * \beta_1}$$

where,

$\beta_{0,a}$	=	constant term estimated by region (see Table F3.1, $\beta_{0,r} = REG_r$)
	=	STCWC_CREG (Appendix E)

β_1	=	1.07386
	=	STCWC_TOTCAP (Appendix E)
t-statistic	=	(2.8)
ρ	=	0.668332
	=	STCWC_RHO (Appendix E)
t-statistic	=	(6.8)
DW	=	1.53
R-Squared	=	0.99

(2) Total Depreciation, Depletion, and Amortization for Existing Capacity

(a) existing capacity (up to 2000 for pipeline and up to 1998 for storage)

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. A linear specification was chosen given that DDA_E is generally believed to be proportional to the level of net plant. The forecasting equation was estimated with a correction for first order serial correlation.

$$DDA_E_{a,t} = DDA_C_a * ARC_a + DDA_NPIS * NPIS_{a,t-1} + DDA_NEWCAP * NEWCAP_E_{a,t}$$

where,

DDA_C_a	=	constant term estimated by arc for the binary variable ARC_a (see Table F3.3, $DDA_C_a = B_ARC_{xx_yy}$)
ARC_a	=	binary variable created for each arc to control for arc specific effects
DDA_NPIS	=	estimated coefficient (see Table F3.3)
DDA_NEWCAP	=	estimated coefficient (see Table F3.3)

The standard errors in Table F3.3 are computed from heteroscedastic-consistent matrix (Robust-White). The results of this regression are reported below:

Dependent variable: DDA_E
Number of observations: 446

Mean of dep. var.	= 25154.4	R-squared	= .995361
Std. dev. of dep. var.	= 33518.3	Adjusted R-squared	= .994761
Sum of squared residuals	= .231907E+10	LM het. Test	= 30.7086 [.000]
Variance of residuals	= .588597E+07	Durbin-Watson	= 2.06651 [<1.00]
Std. error of regression	= 2426.10		

For Storage:

$$STDDA_E_{r,t} = \beta_{0,r} + \beta_1 * STNPIS_E_{r,t-1} + \beta_2 * STNEWCAP_{r,t}$$

where,

$\beta_{0,a}$	=	constant term estimated by region (see Table F3.4, $\beta_{0,r} = REG_r$)
	=	STDDA_CREG (Appendix E)
β_1, β_2	=	(0.032004, 0.028197)
	=	STDDA_NPIS, STDDA_NEWCAP (Appendix E)
t-statistic	=	(10.3) (16.9)
DW	=	1.62
R-Squared	=	0.97

(b) new capacity (generic pipelines and storage)

A regression equation is not used for the new capacity; instead, an accounting algorithm is used (presented in Chapter 6).

(3) Accumulated Deferred Income Taxes for the Combined Existing and New Capacity

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. To control for arc specific effects, a binary variable ARC_a was created for each of the arcs. The associated coefficient represents the arc specific constant term.

Because the level of deferred income taxes is a stock (and not a flow) it was hypothesized that a formulation that focused on the change in the level of accumulated deferred income taxes from the previous year, delta$ADIT_{a,t}$, would be appropriate. Specifically, a linear relationship between the change in ADIT and the change in the level of gross plant in service, $NEWCAP_{a,t}$, and the change in tax policy, POLICY_CHG, was assumed. The form of the estimating equation is:

$$\text{delta } ADIT_{a,t} = ADIT_C_a * ARC_a + \beta_1 * NEWCAP_{a,t} + \beta_2 * NEWCAP_{a,t} + \beta_3 * NEWCAP_{a,t}$$

where,

$ADIT_C_a$	=	constant term estimated by arc for the binary variable ARC_a (see Table F3.5, $ADIT_C_a = B_ARC_{xx_yy}$)
β_1	=	BNEWCAP_PRE2003, estimated coefficient on the change in gross plant in service in the pre-2003 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.
β_2	=	BNEWCAP_2003_2004, estimated coefficient on the change in gross plant in service for the years 2003 and 2004 because of changes in tax policy (Appendix F, Table F3.5). It is zero otherwise.
β_3	=	BNEWCAP_POST2004, estimated coefficient on the change in gross plant in service in the post-2004 period because of changes in tax policy (Appendix F, Table F3.5). It is zero otherwise.

The estimation results are:

Dependent variable: DELTAADIT
Number of observations: 396

Mean of dep. var.	= 6493.50	R-squared	= .464802
Std. dev. of dep. var.	= 17140.8	Adjusted R-squared	= .383664
Sum of squared residuals	= .621120E+11	LM het. test	= 4.03824 [.044]
Variance of residuals	= .181084E+09	Durbin-Watson	= 2.44866 [<1.00]
Std. error of regression	= 13456.8		

For Storage:

$$STADIT_{r,t} = \beta_0 + \beta_1 * STADIT_{r,t-1} + \beta_2 * NEWCAP_{r,t}$$

where,

β_0 = -212.535
= STADIT_C (Appendix E)
β_1, β_2 = (0.921962, 0.212610)
= STADIT_ADIT, STADIT_NEWCAP (Appendix E)
t-statistic = (58.8) (8.4)
DW = 1.69
R-Squared = 0.98

(4) Total Operating and Maintenance Expense for the Combined Existing and New Capacity

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. To control for arc specific effects, a binary variable ARC_a was created for each of the arcs. The associated coefficient represents the arc specific constant term.

The forecasting equation is presented in two stages.

Stage 1:

$$\begin{aligned} Ln(R_TOM_{a,t}) = & TOM_C_a * ARC_a * (1-\rho) + TOM_GPIS1 * Ln(GPIS_{a,t-1}) \\ & + TOM_DEPSHR * DEPSHR_{a,t-1} + TOM_BYEAR * 2006 \\ & + TOM_BYEAR_EIA * (TECHYEAR - 2006.0) + \rho * Ln(R_TOM_{a,t-1}) \\ & - \rho * (TOM_GPIS1 * Ln(GPIS_{a,t-2}) + TOM_DESHR * DEPSHR_{a,t-2} \\ & + TOM_BYEAR * 2006 + TOM_BYEAR_EIA * (TECHYEAR - 1 - 2006.0)) \end{aligned}$$

Stage 2:

$$R_TOM_{a,t} = TOM_K * \exp(Ln(R_TOM_{a,t}))$$

where Ln is a natural logarithm operator and TOM_K is the correction factor estimated in equation two, and where,

TOM_C_a	=	constant term estimated by arc for the binary variable ARCa (see Table F3.6, TOM_Ca = B_ARCxx_yy)
ARC_a	=	binary variable created for each arc to control for arc specific effects
TOM_GPIS1	=	estimated coefficient (see Table F3.6)
TOM_DEPSHR	=	estimated coefficient (see Table F3.6)
TOM_BYEAR	=	estimated coefficient (see Table F3.6)
TOM_BYEAR_EIA	=	future rate of decline in R_TOM due to technology improvements and efficiency gains. EIA assumes that this rate is the same as TOM_BYEAR (see Table F3.6)
ρ	=	first-order autocorrelation, TOM_RHO (see Table F3.6)

The results of this regression are reported below:

Dependent variable: R_TOM
Number of observations: 396

Mean of dep. var.	= 52822.9	LM het. test	= 28.7074 [.000]
Std. dev. of dep. var.	= 76354.9	Durbin-Watson	= 2.01148 [<1.00]
Sum of squared residuals	= .668483E+11	Jarque-Bera test	= 13559.1 [.000]
Variance of residuals	= .169236E+09	Ramsey's RESET2	= 4.03086 [.045]
Std. error of regression	= 13009.1	Schwarz B.I.C.	= 4215.86
R-squared	= .971019	Log likelihood	= -4312.87
Adjusted R-squared	= .971019		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
TOM_K	0.940181	6.691E-03	140.504	[.000]

For Storage:

$$R_STTOM_{r,t} = e^{(\beta_0 * (1-\rho))} * DSTWCAP_{r,t-1}^{\beta_1} * R_STTOM_{r,t-1}^{\rho} * DSTWCAP_{r,t-2}^{-\rho * \beta_1}$$

where,

β_0	=	-6.6702
	=	STTOM_C (Appendix E)
β_1	=	1.44442
	=	STTOM_WORCAP (Appendix E)
t-statistic	=	(33.6)
ρ	=	0.761238
	=	STTOM_RHO (Appendix E)
t-statistic	=	(10.2)
DW	=	1.39
R-Squared	=	0.99

Table F3.1. Summary Statistics for Storage Total Cash Working Capital Equation

Variable	Coefficient	Standard Error	t-statistic
REG2	-2.30334	5.25413	-.438386
REG3	-1.51115	5.33882	-.283049
REG4	-2.11195	5.19899	-.406224
REG5	-2.07950	5.06766	-.410346
REG6	-1.24091	4.97239	-.249559
REG7	-1.63716	5.27950	-.310097
REG8	-2.48339	4.68793	-.529740
REG9	-3.23625	4.09158	-.790954
REG11	-2.15877	4.33364	-.498143

Table F3.2. Summary Statistics for Pipeline Total Cash Working Capital Equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
CWC_TOM	0.381679	.062976	6.06073	[.000]
B_ARC01_01	4.83845	.644360	7.50892	[.000]
B_ARC02_01	5.19554	.644074	8.06668	[.000]
B_ARC02_02	6.37816	.781655	8.15982	[.000]
B_ARC02_03	4.38403	.594344	7.37625	[.000]
B_ARC02_05	5.02364	.684640	7.33764	[.000]
B_ARC03_02	5.51162	.651682	8.45754	[.000]
B_ARC03_03	6.10201	.772378	7.90028	[.000]
B_ARC03_04	4.10475	.572836	7.16566	[.000]
B_ARC03_05	4.69978	.665214	7.06507	[.000]
B_ARC03_15	4.99465	.600910	8.31180	[.000]
B_ARC04_03	5.56047	.718330	7.74083	[.000]
B_ARC04_04	6.15095	.783539	7.85021	[.000]
B_ARC04_07	4.26747	.590736	7.22400	[.000]
B_ARC04_08	4.12216	.611516	6.74089	[.000]
B_ARC05_02	5.50272	.732227	7.51505	[.000]
B_ARC05_03	4.93360	.667589	7.39018	[.000]
B_ARC05_05	6.03791	.774677	7.79409	[.000]
B_ARC05_06	3.27334	.516303	6.33995	[.000]
B_ARC06_03	5.80098	.714338	8.12078	[.000]
B_ARC06_05	5.76939	.741907	7.77644	[.000]
B_ARC06_06	6.73455	.807246	8.34262	[.000]
B_ARC06_07	3.52000	.555549	6.33606	[.000]
B_ARC06_10	4.64811	.665947	6.97970	[.000]
B_ARC07_04	5.60946	.732039	7.66279	[.000]
B_ARC07_06	6.35683	.778573	8.16471	[.000]
B_ARC07_07	6.81298	.828208	8.22616	[.000]
B_ARC07_08	3.60827	.543296	6.64144	[.000]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC07_11	5.89640	.708385	8.32373	[.000]
B_ARC07_21	4.85140	.621031	7.81185	[.000]
B_ARC08_04	4.94307	.678799	7.28208	[.000]
B_ARC08_07	3.97367	.579267	6.85982	[.000]
B_ARC08_08	5.58162	.723678	7.71286	[.000]
B_ARC08_09	5.19274	.635784	8.16746	[.000]
B_ARC08_11	5.12277	.637835	8.03148	[.000]
B_ARC08_12	4.29097	.593945	7.22452	[.000]
B_ARC09_08	4.10222	.576694	7.11333	[.000]
B_ARC09_09	5.44178	.684020	7.95558	[.000]
B_ARC09_12	4.96229	.600227	8.26735	[.000]
B_ARC09_20	2.63716	.448339	5.88207	[.000]
B_ARC11_07	5.58226	.687702	8.11726	[.000]
B_ARC11_08	4.36952	.548152	7.97137	[.000]
B_ARC11_11	6.13044	.728452	8.41571	[.000]
B_ARC11_12	5.93253	.710336	8.35173	[.000]
B_ARC11_22	4.33062	.545420	7.93998	[.000]
B_ARC15_02	5.09861	.583090	8.74412	[.000]
B_ARC16_04	5.03673	.592859	8.49567	[.000]
B_ARC17_04	4.17798	.576943	7.24158	[.000]
B_ARC19_09	5.14500	.618100	8.32389	[.000]
B_ARC20_09	4.58498	.624006	7.34766	[.000]
B_ARC21_07	4.26846	.563536	7.57441	[.000]
CWC_RHO	0.527389	.048379	10.9011	[.000]

Table F3.3. Summary Statistics for Pipeline Depreciation, Depletion, and Amortization Equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
DDA_NEWCAP	.725948E-02	.200846E-02	3.61446	[.000]
DDA_NPIS	.023390	.103991E-02	22.4923	[.000]
B_ARC01_01	4699.58	862.825	5.44674	[.000]
B_ARC02_01	5081.37	853.478	5.95372	[.000]
B_ARC02_02	43769.1	1954.50	22.3940	[.000]
B_ARC02_03	2050.29	814.056	2.51861	[.012]
B_ARC02_05	7876.12	880.047	8.94965	[.000]
B_ARC03_02	5973.21	842.863	7.08681	[.000]
B_ARC03_03	33063.3	1489.77	22.1936	[.000]
B_ARC03_04	1032.74	809.439	1.27588	[.202]
B_ARC03_05	2386.89	845.864	2.82184	[.005]
B_ARC03_15	7652.92	864.810	8.84924	[.000]
B_ARC04_03	19729.5	1118.66	17.6368	[.000]
B_ARC04_04	35522.7	2267.45	15.6663	[.000]
B_ARC04_07	1919.97	811.222	2.36677	[.018]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC04_08	747.069	822.607	.908172	[.364]
B_ARC05_02	15678.2	1114.41	14.0686	[.000]
B_ARC05_03	6452.49	855.092	7.54596	[.000]
B_ARC05_05	45000.5	1771.82	25.3979	[.000]
B_ARC05_06	446.742	809.035	.552191	[.581]
B_ARC06_03	11967.8	942.879	12.6928	[.000]
B_ARC06_05	22576.3	1243.19	18.1599	[.000]
B_ARC06_06	67252.9	2892.23	23.2530	[.000]
B_ARC06_07	1134.14	809.115	1.40170	[.161]
B_ARC06_10	15821.4	989.531	15.9888	[.000]
B_ARC07_04	15041.4	984.735	15.2746	[.000]
B_ARC07_06	48087.6	1908.12	25.2015	[.000]
B_ARC07_07	80361.2	3384.54	23.7436	[.000]
B_ARC07_08	833.829	809.565	1.02997	[.303]
B_ARC07_11	4732.17	928.814	5.09486	[.000]
B_ARC07_21	1452.16	922.486	1.57418	[.115]
B_ARC08_04	4920.06	1022.86	4.81008	[.000]
B_ARC08_07	1425.79	811.348	1.75731	[.079]
B_ARC08_08	34661.3	1694.49	20.4553	[.000]
B_ARC08_09	5962.90	873.649	6.82528	[.000]
B_ARC08_11	1088.95	824.202	1.32122	[.186]
B_ARC08_12	7610.79	899.215	8.46382	[.000]
B_ARC09_08	2857.54	814.127	3.50994	[.000]
B_ARC09_09	15070.9	1021.78	14.7496	[.000]
B_ARC09_12	3120.00	833.569	3.74295	[.000]
B_ARC09_20	279.322	917.025	.304595	[.761]
B_ARC11_07	4022.68	871.680	4.61485	[.000]
B_ARC11_08	325.210	809.288	.401846	[.688]
B_ARC11_11	5616.89	1025.31	5.47822	[.000]
B_ARC11_12	4041.93	940.189	4.29906	[.000]
B_ARC11_22	259.293	809.060	.320487	[.749]
B_ARC15_02	2125.53	812.198	2.61701	[.009]
B_ARC16_04	8017.53	871.030	9.20465	[.000]
B_ARC17_04	3316.38	860.323	3.85481	[.000]
B_ARC19_09	4216.02	853.774	4.93810	[.000]
B_ARC20_09	6238.31	834.249	7.47776	[.000]
B_ARC21_07	666.813	810.034	.823192	[.410]

Table F3.4. Summary Statistics for Storage Depreciation, Depletion, and Amortization Equation

Variable	Coefficient	St-Error	t-statistic
REG2	4485.56	1204.28	3.72467
REG3	6267.52	1806.17	3.47006
REG4	3552.55	728.230	4.87833
REG5	2075.31	646.561	3.20976
REG6	1560.07	383.150	4.07169
REG7	4522.42	1268.87	3.56412
REG8	1102.49	622.420	1.77129
REG9	65.2731	10.1903	6.40542
REG11	134.692	494.392	.272439

Table F3.5. Summary Statistics for Pipeline Accumulated Deferred Income Tax Equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
BNEWCAP_PRE2003	.067242	.023235	2.89405	[.004]
BNEWCAP_2003_2004	.132014	.013088	10.0865	[.000]
BNEWCAP_POST2004	.109336	.028196	3.87766	[.000]
B_ARC01_01	3529.80	4775.58	.739134	[.460]
B_ARC02_01	2793.71	4766.40	.586125	[.558]
B_ARC02_02	15255.3	5318.30	2.86844	[.004]
B_ARC02_03	767.648	4758.23	.161331	[.872]
B_ARC02_05	2479.86	4768.91	.520005	[.603]
B_ARC03_02	1663.09	4761.98	.349243	[.727]
B_ARC03_03	6184.51	4966.65	1.24521	[.213]
B_ARC03_04	-14.6495	4757.75	-.307908E-02	[.998]
B_ARC03_05	3183.89	4761.49	.668676	[.504]
B_ARC03_15	2531.19	4759.07	.531866	[.595]
B_ARC04_03	3660.65	4780.00	.765826	[.444]
B_ARC04_04	6076.87	4900.20	1.24013	[.215]
B_ARC04_07	-391.339	4757.90	-.082250	[.934]
B_ARC04_08	1798.04	4758.19	.377884	[.706]
B_ARC05_02	6654.17	4801.91	1.38573	[.166]
B_ARC05_03	1842.90	4762.25	.386982	[.699]
B_ARC05_05	6344.87	5220.98	1.21526	[.224]
B_ARC05_06	148.421	4757.73	.031196	[.975]
B_ARC06_03	2475.65	4775.18	.518441	[.604]
B_ARC06_05	5193.49	4996.38	1.03945	[.299]
B_ARC06_06	24991.1	5803.11	4.30650	[.000]
B_ARC06_07	-259.276	4757.72	-.054496	[.957]
B_ARC06_10	13015.7	4862.80	2.67659	[.007]
B_ARC07_04	189.221	4776.34	.039616	[.968]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC07_06	14166.3	5012.13	2.82640	[.005]
B_ARC07_07	16102.7	5680.52	2.83472	[.005]
B_ARC07_08	118.047	4758.11	.024810	[.980]
B_ARC07_11	-434.842	4808.84	-.090426	[.928]
B_ARC07_21	495.934	5498.36	.090197	[.928]
B_ARC08_04	4679.95	4780.56	.978955	[.328]
B_ARC08_07	365.793	4762.84	.076801	[.939]
B_ARC08_08	5133.64	5235.92	.980466	[.327]
B_ARC08_09	-3672.71	4770.23	-.769923	[.441]
B_ARC08_11	-1856.45	4762.76	-.389784	[.697]
B_ARC08_12	795.831	4808.51	.165505	[.869]
B_ARC09_08	537.433	4759.95	.112907	[.910]
B_ARC09_09	-1812.27	4829.76	-.375230	[.707]
B_ARC09_12	-2803.40	4761.86	-.588719	[.556]
B_ARC09_20	55.5366	5493.73	.010109	[.992]
B_ARC11_07	-1137.92	4772.21	-.238448	[.812]
B_ARC11_08	276.612	4757.86	.058138	[.954]
B_ARC11_11	7.99239	4874.89	.163950E-02	[.999]
B_ARC11_12	-1079.76	4825.77	-.223750	[.823]
B_ARC11_22	337.987	4759.18	.071018	[.943]
B_ARC15_02	429.875	4758.19	.090344	[.928]
B_ARC16_04	2744.23	4759.07	.576631	[.564]
B_ARC17_04	935.795	4757.97	.196680	[.844]
B_ARC19_09	-3806.27	4762.95	-.799141	[.424]
B_ARC20_09	1173.22	4768.48	.246037	[.806]
B_ARC21_07	586.673	4759.84	.123255	[.902]

Table F3.6. Summary Statistics for Pipeline Total Operating and Maintenance Expense Equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
TOM_GPIS1	.256869	.114518	2.24304	[.025]
TOM_DEPSHR	1.69807	.429440	3.95415	[.000]
TOM_BYEAR	-.019974	.718590E-02	-2.77955	[.005]
B_ARC01_01	45.8116	13.5505	3.38081	[.001]
B_ARC02_01	45.7428	13.5502	3.37580	[.001]
B_ARC02_02	47.4313	13.4380	3.52963	[.000]
B_ARC02_03	45.3570	13.6230	3.32944	[.001]
B_ARC02_05	46.3936	13.5393	3.42658	[.001]
B_ARC03_02	45.8277	13.5539	3.38115	[.001]
B_ARC03_03	47.1662	13.4461	3.50779	[.000]
B_ARC03_04	44.5365	13.6401	3.26512	[.001]
B_ARC03_05	45.9318	13.5464	3.39071	[.001]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC03_15	45.1262	13.5508	3.33015	[.001]
B_ARC04_03	46.5137	13.4799	3.45060	[.001]
B_ARC04_04	47.4725	13.4290	3.53508	[.000]
B_ARC04_07	45.0325	13.6249	3.30516	[.001]
B_ARC04_08	45.6096	13.5965	3.35451	[.001]
B_ARC05_02	46.8361	13.4859	3.47298	[.001]
B_ARC05_03	46.2316	13.5556	3.41052	[.001]
B_ARC05_05	47.2881	13.4422	3.51788	[.000]
B_ARC05_06	44.2555	13.6969	3.23105	[.001]
B_ARC06_03	46.4249	13.4976	3.43948	[.001]
B_ARC06_05	46.9210	13.4730	3.48260	[.000]
B_ARC06_06	47.6072	13.4045	3.55157	[.000]
B_ARC06_07	44.5090	13.6696	3.25606	[.001]
B_ARC06_10	46.0547	13.5171	3.40715	[.001]
B_ARC07_04	46.6884	13.4905	3.46084	[.001]
B_ARC07_06	47.2664	13.4316	3.51904	[.000]
B_ARC07_07	47.8651	13.3928	3.57395	[.000]
B_ARC07_08	44.7096	13.6750	3.26944	[.001]
B_ARC07_11	46.7847	13.5263	3.45880	[.001]
B_ARC07_21	45.4067	13.6138	3.33535	[.001]
B_ARC08_04	46.3290	13.5124	3.42864	[.001]
B_ARC08_07	45.1349	13.6437	3.30810	[.001]
B_ARC08_08	46.8373	13.4658	3.47825	[.001]
B_ARC08_09	45.7056	13.5495	3.37323	[.001]
B_ARC08_11	45.9766	13.5925	3.38250	[.001]
B_ARC08_12	45.1596	13.5537	3.33190	[.001]
B_ARC09_08	44.9927	13.6211	3.30317	[.001]
B_ARC09_09	46.2997	13.5103	3.42699	[.001]
B_ARC09_12	45.2655	13.5793	3.33342	[.001]
B_ARC09_20	43.2644	13.7686	3.14226	[.002]
B_ARC11_07	46.4472	13.5409	3.43015	[.001]
B_ARC11_08	44.9105	13.6898	3.28058	[.001]
B_ARC11_11	47.0985	13.5107	3.48603	[.000]
B_ARC11_12	46.8744	13.5270	3.46526	[.001]
B_ARC11_22	44.8071	13.7118	3.26778	[.001]
B_ARC15_02	44.8267	13.6116	3.29327	[.001]
B_ARC16_04	45.0068	13.5491	3.32175	[.001]
B_ARC17_04	44.8832	13.5582	3.31042	[.001]
B_ARC19_09	45.4861	13.5613	3.35412	[.001]
B_ARC20_09	45.5729	13.5745	3.35725	[.001]
B_ARC21_07	44.6298	13.6465	3.27041	[.001]
TOM_RHO	.297716	.052442	5.67707	[.000]

Table F4

Data: Equation for industrial distribution tariffs

Author: Ernest Zampelli, SAIC, 2009.

Source: The source for the peak and off-peak consumption data used in this estimation was the Natural Gas Monthly, DOE/EIA-0130. State level city gate prices by month were averaged using quantity-weights to arrive at seasonal (peak and off-peak), regional level (12 NGTDM regions) prices. The quantity-weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. Prices for the estimations were derived as described in Table F5.

Variables:

$TIN_{r,n,t}$	=	industrial distributor tariff in region r, network n (1987 dollars per Mcf) [$DTAR_SF_3$]
$PREG_r$	=	1, if observation is in region r during peak period (n=1), =0 otherwise
$QIND_{r,t}$	=	industrial gas consumption in region r in year t (MMcf) [$BASQTY_SF_3$+$BASQTY_SI_3$]
r	=	NGTDM region
t	=	year
α_0, α_r, $\alpha_{r,n}$	=	estimated parameters for regional constants [$PINREG15_r$ and $PINREGPK15_{r,n}$]
β	=	estimated parameter for consumption
ρ	=	autocorrelation coefficient

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The industrial distributor tariff equation was estimated using backcasted data for the 12 NGTDM regions over the 1990 to 2008 time period. The equation was estimated in linear form with corrections for cross sectional heteroscedasticity and first order serial correlation using TSP version 5.0. The form of the estimating equation follows:

$$\ln TIN_{r,n,t} = \alpha_0 + \sum_r (\alpha_r + \alpha_{r,pk}) * REG_{r,pk} + \beta * QIND_{r,t} + \rho * TIN_{r,t-1}$$
$$- \rho * (\sum_r (\alpha_r + \alpha_{r,pk}) * REG_{r,pk} + \beta * QIND_{r,t-1})$$

Regression Diagnostics and Parameter Estimates:

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

Dependent variable: TIN87
Number of observations: 456

Mean of dep. var.	=	.282327	R-squared	=	.711027
Std. dev. of dep. var.	=	1.68053	Adjusted R-squared	=	.703199
Sum of squared residuals	=	371.429	Durbin-Watson	=	1.96827

Variance of residuals	= .838440	Schwarz B.I.C.	= 640.302
Std. error of regression	= .915663	Log likelihood	= -600.506

Parameter	Estimate	Standard Error	t-statistic	P-value	Code Variable
WT	.199135	.041539	4.79396	[.000]	
NE	.664368	.178794	3.71584	[.000]	$PINREG15_1$
WNCNTL	-.565428	.069519	-8.13339	[.000]	$PINREG15_4$
ESCNTL	-.248102	.053509	-4.63666	[.000]	$PINREG15_6$
AZNM	.395943	.093005	4.25725	[.000]	$PINREG15_{11}$
CA	.605914	.097865	6.19132	[.000]	$PINREG15_{12}$
MIDATL_PK	.418090	.101754	4.10881	[.000]	$PINREGPK15_2$
WNCNTL_PK	.354066	.079415	4.45840	[.000]	$PINREGPK15_4$
ESCNTL_PK	.203711	.074239	2.74398	[.006]	$PINREGPK15_6$
WSCNTL_PK	-.411782	.068533	-6.00852	[.000]	$PINREGPK15_7$
WAOR_PK	.263996	.092401	2.85709	[.004]	$PINREGPK15_9$
QIND	-.317443E-03	.482650E-04	-6.57708	[.000]	
RHO	.423561	.043665	9.70021	[.000]	

Standard Errors computed from analytic second derivatives (Newton)

Data used for estimation

		New Engl.	Mid Atl.	E.N. Central	W.N. Central	S.Atl Fl	E.S. Central	W.S. Central	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
		1	2	3	4	5	6	7	8	9	10	11	12
1990 QIN	peak	25.238	156.14	453.96	140.9	185.23	152.15	948.57	56.599	46.146	30.06	13.198	177.12
1990 QIN	off-peak	56.095	270.87	730.76	245.05	351.31	272.39	1987.3	93.839	81.168	54.881	24.473	388.08
1991 QIN	peak	39.282	168.91	481.69	149.95	171.26	158.54	979.32	66.408	47.282	30.235	14.3	201.54
1991 QIN	off-peak	82.376	282.18	729.31	254.99	330.64	288.33	2003.6	109.22	87.502	53.163	24.25	401.08
1992 QIN	peak	54.227	204.09	498.51	155.99	185.1	166.54	1018.4	74.334	49.691	29.904	13.778	217.12
1992 QIN	off-peak	108.78	354.7	777.87	263.94	353.2	304.97	1942.1	128.69	88.594	54.925	23.066	377.45
1993 QIN	peak	61.814	224.11	529.31	166.97	185.5	176.42	1045.5	83.593	54.178	34.299	13.167	214.7
1993 QIN	off-peak	123.32	366.69	786.37	283.17	358.16	305.77	2109.2	148.52	98.713	66.051	25.02	445.02
1994 QIN	peak	60.862	243.6	553.36	190.76	182.9	170.14	1088.8	91.076	58.07	42.837	13.711	210.07
1994 QIN	off-peak	111.77	398.1	795.93	320.33	380.72	299.53	2069.5	149.79	112.1	84.036	30.899	446.68
1995 QIN	peak	67.612	274.81	564.08	174.94	198.2	181.21	1094.8	92.348	62.974	49.496	18.42	216.02
1995 QIN	off-peak	117.09	462.71	842.05	302.97	408.65	323.96	2206	154.12	115.93	83.981	30.338	471.9
1996 QIN	peak	54.363	285.51	578.99	166.26	193.94	178.95	1196.9	93.314	66.644	46.056	17.943	231.69
1996 QIN	off-peak	112.99	481.59	876.22	283.25	385.99	324.38	2332	168.08	135.35	90.666	31.894	461.85
1997 QIN	peak	48.405	234.18	527.5	180.9	213.68	185.66	1158.6	77.997	70.675	41.903	18.414	232.69
1997 QIN	off-peak	86.131	402.1	814.07	291.91	398.91	334.13	2246.7	136.03	130.89	83.234	35.325	487.2
1998 QIN	peak	52.54	226.19	506.96	165.78	200.57	186.74	1119.4	94.347	83.184	40.685	18.07	232.48
1998 QIN	off-peak	95.549	375.1	771.51	298.64	370.18	328.87	2140.8	154.17	152.69	81.23	35.135	513.67
1999 QIN	peak	55.157	197.85	523.25	160.89	221.22	201	1023.2	77.398	81.611	43.813	18.686	203.63
1999 QIN	off-peak	100.84	332.74	804.58	274.65	340.85	366.69	2032.3	146.67	150.74	90.394	34.188	522.78
2000 QIN	peak	54.493	152.64	539.34	163.07	194.49	200.21	1080.9	87.687	57.099	35.056	17.259	218.27
2000 QIN	off-peak	86.042	262.25	788.24	285.56	364.74	347.3	2230.3	139.76	102.92	69.631	33.847	558.47
2001 QIN	peak	49.565	139.45	480.99	150.12	155.17	168.54	1051.7	104.16	50.923	30.792	19.007	211.11
2001 QIN	off-peak	85.579	228.74	699.46	258.24	303.54	299.32	1974.5	167.1	93.96	63.919	35.375	455.88
2002 QIN	peak	52.54	144.33	470.45	121.75	173.22	176.85	1011.8	91.637	51.527	28.746	14.516	241.23
2002 QIN	off-peak	81.724	234.44	758.81	221.6	328.78	305.4	2005.8	169.31	86.7	54.823	26.005	499.44
2003 QIN	peak	39.744	139.83	481.39	158.53	175.69	176.28	982.91	89.808	47.009	25.345	13.858	252.4
2003 QIN	off-peak	46.063	215.76	678.89	260.18	298.39	286.67	1906.9	146.28	86.394	47.99	25.8	527.13

		New Engl.	Mid Atl.	E.N. Central	W.N. Central	S.Atl Fl	E.S. Central	W.S. Central	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
		1	2	3	4	5	6	7	8	9	10	11	12
2004 QIN	peak	37.198	136.43	491.51	156.64	176.4	173.92	973.99	91.339	49.641	23.374	16.187	271.43
2004 QIN	off-peak	45.242	214.24	688.46	265.89	305.66	303.33	1907	146.72	89.858	40.229	26.574	564.84
2005 QIN	peak	40.728	135.24	478.91	158.08	172.16	168.5	808.09	93.829	48.327	23.015	14.013	267.71
2005 QIN	off-peak	45.586	205.31	681.74	260.6	290.89	283.02	1538.7	159.82	88.192	40.118	27.785	514.11
2006 QIN	peak	35.807	124.55	429.28	162.89	161.04	157.39	787.35	97.212	50.66	24.302	13.762	244.48
2006 QIN	off-peak	47.391	207.44	673.41	298.82	305.01	292.01	1573.2	151.07	90.187	45.419	22.924	488.02
2007 QIN	peak	39.898	129.41	455.49	173.06	161.02	166.6	834.3	97.509	51.108	23.489	13.67	243.44
2007 QIN	off-peak	47.76	206.79	665.3	304.43	293.52	287.93	1612	156.13	91.117	42.303	23.336	490.16
2008 QIN	peak	41.994	131.75	450.39	195.27	158.12	162.98	834.03	101.53	55.157	25.683	13.962	255.11
2008 QIN	off-peak	45.87	195.97	644.85	323.08	290.82	281.62	1594.9	157.55	89.092	45.653	24.509	509.07
1990 TIN	peak	1.099	0.6688	0.3058	-0.1288	0.7025	0.1655	-0.5898	0.0125	0.6006	0.5055	0.3569	0.7677
1990 TIN	off-peak	0.2422	0.2975	0.3219	-0.2679	0.3332	0.0103	-0.8011	-0.6182	0.3989	0.6069	0.4618	0.4976
1991 TIN	peak	1.1651	0.7854	0.3182	-0.1239	0.6413	0.1569	-0.6598	-0.2375	0.5443	0.4694	0.4572	0.9729
1991 TIN	off-peak	0.2206	0.1636	0.1991	-0.3464	0.1277	-0.0513	-0.6584	-0.7412	0.4784	0.5472	0.3259	0.5807
1992 TIN	peak	1.2819	0.6984	0.2446	-0.0567	0.628	0.1737	-0.6297	-0.1706	0.5218	0.5658	1.2426	1.078
1992 TIN	off-peak	-0.1136	-0.164	-0.0413	-0.3214	0.0843	-0.1326	-0.5803	-0.9941	0.5634	0.4786	0.9993	0.2713
1993 TIN	peak	1.1049	0.5098	0.1875	-0.0766	0.6265	0.1938	-0.5649	-0.1407	0.4983	0.5495	0.7831	0.3072
1993 TIN	off-peak	-0.5318	-0.1649	0.0392	-0.3932	0.0085	-0.1049	-0.4782	-0.5373	0.4175	0.689	0.6653	-0.1804
1994 TIN	peak	1.1511	0.6644	0.3775	0.043	0.5115	0.3493	-0.4724	-0.4511	0.4197	0.0552	0.989	0.4388
1994 TIN	off-peak	-0.7697	0.0425	0.2089	-0.4502	-0.1338	-0.0533	-0.3722	-0.6965	0.1884	0.2237	0.5148	0.1871
1995 TIN	peak	0.9682	0.5415	0.1336	0.0336	0.5657	0.368	-0.5873	-0.1514	0.2735	-0.0042	1.0843	1.3996
1995 TIN	off-peak	-0.6908	0.1533	-0.0909	-0.4184	0.0587	-0.091	-0.5336	-0.1512	0.2563	0.1373	0.8486	0.7801
1996 TIN	peak	1.0885	0.4724	-0.0801	0.1501	0.3852	-0.0597	-0.2293	0.0624	0.3147	0.0629	0.7245	0.7635
1996 TIN	off-peak	-0.5643	-0.1022	-0.0573	-0.4768	0.0265	0.0109	-0.287	0.0885	0.0274	0.2877	0.6701	0.549
1997 TIN	peak	0.9536	0.5591	0.1766	-0.1368	0.4308	0.1911	-0.4936	0.04	0.5014	-0.2748	0.3125	1.0975
1997 TIN	off-peak	-0.3627	-0.9394	-0.1531	-0.7348	-0.0943	-0.0291	-0.2262	0.2046	0.0767	0.1115	0.1918	0.4767
1998 TIN	peak	0.7314	0.029	0.1798	-0.0513	0.1833	0.0944	-0.2879	-0.1103	0.1663	-0.0655	0.544	1.0797
1998 TIN	off-peak	-0.8255	-0.5106	0.0985	-0.5266	-0.3471	-0.2757	-0.1983	0.0953	0.0643	-0.0713	0.176	0.4421
1999 TIN	peak	0.381	0.1165	0.1777	-0.0447	-0.0503	0.1269	-0.4494	0.5426	0.1491	0.6896	0.5158	0.6471
1999 TIN	off-peak	-0.8161	-0.787	-0.2143	-0.5001	-0.4758	-0.2064	-0.2569	0.2023	0.0292	-0.0932	0.0834	0.2283
2000 TIN	peak	0.4368	0.3257	-0.1319	-0.1978	-0.0355	-0.0918	-0.5133	0.3527	0.5765	-0.0681	-0.0613	0.6967
2000 TIN	off-peak	-0.6324	-0.5654	-0.2139	-0.637	-0.4437	-0.2846	-0.3444	0.3139	-0.0557	0.2312	-0.0438	0.5583
2001 TIN	peak	-0.0298	0.5579	0.0726	-0.3949	-0.0079	-0.2461	-0.7083	0.157	-0.2738	-0.3584	-0.0328	-0.4836
2001 TIN	off-peak	-0.1169	0.2263	0.2662	-0.493	-0.4109	-0.0722	-0.3964	0.7435	0.3807	0.8896	0.7614	0.8027
2002 TIN	peak	0.6619	0.4506	-0.1471	-0.2	-0.0309	0.19	-0.5569	0.8717	0.7349	0.8584	1.2169	1.054
2002 TIN	off-peak	-0.875	0.1446	-0.447	-0.351	-0.4161	-0.0017	-0.4194	0.9103	-0.0871	0.4439	0.6581	0.6936
2003 TIN	peak	0.7842	1.1901	0.0288	-0.3011	0.018	0.3513	-0.222	0.5963	0.2737	-0.4933	0.3882	1.0483
2003 TIN	off-peak	0.2361	0.7713	0.1791	-0.4924	-0.4897	-0.3577	-0.2159	0.6595	0.1605	0.5482	0.6927	0.8708
2004 TIN	peak	1.2662	0.958	0.1488	-0.1974	0.0588	0.1299	-0.4422	0.2895	0.3958	0.1907	0.4129	1.176
2004 TIN	off-peak	0.17	0.2825	-0.2684	-0.6077	-0.4935	-0.1755	-0.1804	0.2801	0.0213	0.433	0.4578	0.4561
2005 TIN	peak	1.1769	0.9548	-0.071	0.0804	0.1706	0.2596	-0.513	0.4996	0.5463	-0.0684	0.4173	1.3857
2005 TIN	off-peak	6.2644	0.1607	-0.6005	-0.8601	-0.6412	-0.2335	-0.2605	0.2672	0.0206	-0.6922	0.4917	0.3082
2006 TIN	peak	0.7955	0.6048	-0.3683	0.1022	-0.2335	0.0381	-0.6599	0.3446	0.3204	0.599	0.3567	1.2178
2006 TIN	off-peak	0.2617	-0.7368	-0.1778	-0.7105	-0.4412	-0.3876	-0.4774	0.2411	0.1519	1.1891	1.1094	0.9437
2007 TIN	peak	1.3417	0.2697	-0.3644	0.0452	0.1393	-0.1848	-0.7233	-0.0415	0.6403	0.7626	0.7061	0.907
2007 TIN	off-peak	0.2215	-0.0402	-0.1513	-0.3497	-0.1962	-0.1132	-0.7936	0.3232	0.5507	0.9501	0.8721	0.8912
2008 TIN	peak	1.1063	0.3597	-0.1709	0.1381	0.1855	-0.1638	-0.62	0.1363	0.8461	1.0509	0.5912	0.9421
2008 TIN	off-peak	0.5047	0.3785	0.2288	-0.1025	-0.0856	-0.255	-0.6044	0.071	-0.1388	1.2117	1.1816	1.1883

Table F5

Data: Historical industrial sector natural gas prices by type of service, NGTDM region.

Derivation: The historical industrial natural gas prices published in the *Natural Gas Annual (NGA)* only reflect gas purchased through local distribution companies. In order to approximate the average price to all industrial customers by service type and NGTDM region (HPGFINGR, HPGIINGR), data available at the Census Region level[97] from the Manufacturing Energy Consumption Survey (MECS)[98] for the years 1988, 1991, 1994, 1998, and 2002 were used to estimate an equation for the regional MECS price as a function of the regional NGA industrial price and the regional supply price (quantity-weighted average of the gas wellhead price and import price). The procedure is outlined below.

1) Assign average Census Division industrial price using econometrically derived equation:

$$PIN_NG_{nr} = 1.00187 * \exp(0.039682) * PW_NRG_{nr}^{0.231404} * HPIN_{nr}^{0.726227}$$

from estimating the following equation

$$\ln PIN_NG_{nr} = \beta_0 + \beta_1 * \ln PW_NRG_{nr} + \beta_2 * HPIN_{nr}$$

2) Assign prices to the NGTDM regions that represent subregions of Census Divisions by multiplying the Census Division price from step 1 by the subregion price (as published in the NGA), divided by the Census Division price (as published in the NGA). For the Pacific Division, the industrial price in Alaska from the NGA, with quantity weights, is used to approximate a Pacific Division price for the lower-48 (i.e., CA, WA, and OR), before this step is performed.

3) Core industrial prices are derived by applying an historical, regional, average average-to-firm price markup (FDIFF, in 1987$/Mcf, Northeast 0.11, North Central 0.14, South 0.67, West 0.39) to the established average regional industrial price (from step 2). Noncore prices are calculated so that the quantity-weighted average of the core and noncore prices equal the original regional estimate. The data used to generate the average-to-firm markups are presented below.

4) Finally, the peak and off-peak prices from the NGA are scaled to align with the core and noncore prices generated from step 3 on an average annual basis, to arrive at peak/off-peak, core/noncore industrial prices for the NGTDM regions.

[97] Through a special request, the Census Bureau generated MECS data by Census Region and by service type (core versus noncore) based on an assumption of which industrial classifications are more likely to consume most of their purchased natural gas in boilers (core) or non-boiler applications (noncore).

[98] A request was issued to the Census Bureau to obtain similar data from other MECS surveys to improve this estimation.

	Prices (87$/mcf)			Consumption (Bcf)		
	1988	**1991**	**1994**	**1988**	**1991**	**1994**
Core						
Northeast	3.39	3.05	3.04	335	299	310
North Central	3.04	2.37	2.42	864	759	935
South	2.91	2.40	2.53	643	625	699
West	3.21	2.70	2.55	217	204	227
Noncore						
Northeast	3.05	2.78	2.67	148	146	187
North Central	2.60	2.01	2.17	537	648	747
South	1.96	1.57	1.75	2517	2592	2970
West	2.54	2.19	1.91	347	440	528

	Price (87$/mcf)				
	1988	1991	1994	1998	2002
Northeast	3.297223	3.018058	2.941269	2.834076	3.498869
North Central	2.880355	2.247968	2.351399	2.247715	2.985983
South	2.162684	1.766014	1.939298	1.947017	2.634691
West	2.804912	2.398525	2.133228	2.217645	2.831414

Variables:

PIN_NG = Industrial natural gas prices by NGTDM region (1987$/Mcf)
PW_CDV = Average supply price by Census Division (1987$/Mcf)
PI_CDV = Industrial natural gas price from the NGA by Census Division (1987$/Mcf)
FDIFF = Average (1988, 1991, 1994) difference between the firm industrial price and the average industrial price by Census Region (1987$/Mcf)
PIN_FNG = Industrial core natural gas prices by NGTDM region (1987$/Mcf)
PIN_ING = Industrial noncore natural gas prices by NGTDM region (1987$/Mcf)
HPGFINGR = Industrial core natural gas prices by period and NGTDM region (1987$/Mcf)
HPGIINGR = Industrial noncore natural gas prices by period and NGTDM region (1987$/Mcf)

Regression Diagnostics and Parameter Estimates:

```
Dependent variable: LNMECS87
 Number of observations:  20

       Mean of dep. var. = .921802          LM het. test = .021529 [.883]
  Std. dev. of dep. var. = .190034         Durbin-Watson = 1.22472 [<.086]
Sum of squared residuals = .067807      Jarque-Bera test = .977466 [.613]
   Variance of residuals = .398866E-02   Ramsey's RESET2 = .044807 [.835]
```

```
 Std. error of regression = .063156       F (zero slopes) = 77.5121 [.000]
               R-squared = .901177        Schwarz B.I.C. = -23.9958
      Adjusted R-squared = .889550        Log likelihood = 28.4894

              Estimated    Standard
 Variable     Coefficient     Error       t-statistic   P-value   Symbol
 C            .039682       .072242       .549291       [.590]    β0
 LNSUPPLYP87  .231404       .105606       2.19120       [.043]    β1
 LNNGAP87     .726227       .073700       9.85385       [.000]    β2
```

Form of Forecasting Equation:

$$MECS87 = 1.00187 * e^{0.039682} SUPPLYP87^{0.231404} NGAP87^{0.726227}$$

where:

*MECS*87 = Manufacturer's Energy Consumption Survey in US$87

*SUPPLYP*87 = supply price in US$87

*NGAP*87 = natural gas annual price in US$87

The term 1.00187 is an adjustment factor that is applied in cases where the value of "y" is predicted from an estimated equation where the dependent variable is the natural log of y. The adjustment is due to the fact that generally predictions of "y" using the first equation only tend to be biased downward. It is calculated by estimating the historical values of the dependent variable as a function of the estimated values for the same.

Table F6

Data: Equations for residential distribution tariffs

Author: Ernest Zampelli, SAIC, with summer intern Ben Laughlin, 2010.

Source: The source for the peak and off-peak data used in this estimation was the *Natural Gas Monthly*, DOE/EIA-0130. State level city gate and residential prices by month were averaged using quantity-weights to arrive at seasonal (peak and off-peak), regional level (12 NGTDM regions) prices. The quantity-weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. The source for the number of residential customers was the Natural Gas Annual, DOE/EIA-0131.

Variables:

$TRS_{r,n,t}$	=	residential distributor tariff in the period n for region r (1987 dollars per Mcf) [$DTAR_SF_1$]
REG_r	=	1, if observation is in region r, =0 otherwise
$QRS_NUMR_{r,n,t}$	=	residential gas consumption per customer in the period for region r in year t (Bcf per thousand customers) [$(BASQTY_SF_1+BASQTY_SI_1)/NUMRS$]
$NUMRS_{r,t}$	=	number of residential customers (thousands)
r	=	NGTDM region
n	=	network (1=peak, 2=off-peak)
t	=	year
$\alpha_{r,n}$	=	estimated parameters for regional dummy variables [PRSREGPK19]
$\beta_{1,n}$, $\beta_{2,n}$	=	estimated parameters
ρ_n	=	autocorrelation coefficient

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: Residential distributor tariff equations for the peak and off-peak periods were estimated using panel data for the 12 NGTDM regions over the 1990 to 2009 time period. The equations were estimated in log-linear form with corrections for cross sectional heteroscedasticity and first order serial correlation using EViews. The general form for both estimating equations follows:

$$\ln TRS_{r,n,t} = \sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QRS_NUMR_{r,n,t} + \beta_{2,n} * \ln NUMRS_{r,t} +$$

$$\rho_n * \ln TRS_{r,n,t-1} - \rho_n * (\sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QRS_NUMR_{r,n,t-1} + \beta_{2,n} * \ln NUMRS_{r,t-1}$$

Regression Diagnostics and Parameter Estimates for the Peak Period:

Dependent Variable: LNTRS87
Method: Least Squares
Date: 07/22/10 Time: 16:32
Sample (adjusted): 2 240
Included observations: 239 after adjustments
Convergence achieved after 7 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=4)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQRS_NUMR	-0.607267	0.094552	-6.422580	0.0000
LN_NUMRS	0.162972	0.090462	1.801551	0.0730
REGION=1	-6.947036	1.103041	-6.298074	0.0000
REGION=2	-7.422527	1.201445	-6.178001	0.0000
REGION=3	-8.021596	1.217912	-6.586353	0.0000
REGION=4	-7.864109	1.156385	-6.800599	0.0000
REGION=5	-7.473760	1.153979	-6.476514	0.0000
REGION=6	-7.664540	1.121958	-6.831398	0.0000
REGION=7	-8.052452	1.177230	-6.840170	0.0000
REGION=8	-7.987073	1.121141	-7.124058	0.0000
REGION=9	-7.308704	1.060240	-6.893446	0.0000
REGION=10	-7.283411	1.060717	-6.866500	0.0000
REGION=11	-7.523595	1.085943	-6.928169	0.0000
REGION=12	-7.954022	1.209662	-6.575410	0.0000
AR(1), ρ	0.231296	0.068422	3.380459	0.0009

R-squared	0.911539	Mean dependent var	0.940050
Adjusted R-squared	0.906010	S.D. dependent var	0.384204
S.E. of regression	0.117789	Akaike info criterion	-1.379145
Sum squared resid	3.107810	Schwarz criterion	-1.160957
Log likelihood	179.8078	Hannan-Quinn criter.	-1.291221
Durbin-Watson stat	1.994101		

Regression Diagnostics and Parameter Estimates for the Off-peak Period:

Dependent Variable: LNTRS87
Method: Least Squares
Date: 07/22/10 Time: 16:31
Sample: 241 480
Included observations: 240
Convergence achieved after 6 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=4)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQRS_NUMR	-0.814968	0.085444	-9.538040	0.0000
LN_NUMRS	0.282301	0.111488	2.532127	0.0120
REGION=1	-11.06556	1.189130	-9.305589	0.0000
REGION=2	-11.46569	1.331512	-8.611025	0.0000
REGION=3	-11.99084	1.365602	-8.780628	0.0000
REGION=4	-11.81121	1.265735	-9.331497	0.0000
REGION=5	-11.52214	1.266859	-9.095045	0.0000
REGION=6	-11.67063	1.209285	-9.650856	0.0000

REGION=7	-11.86662	1.278193	-9.283902	0.0000
REGION=8	-11.80703	1.229651	-9.601944	0.0000
REGION=9	-11.19628	1.140432	-9.817580	0.0000
REGION=10	-10.93813	1.060071	-10.31830	0.0000
REGION=11	-11.32604	1.134872	-9.980016	0.0000
REGION=12	-12.06455	1.327790	-9.086182	0.0000
AR(1), ρ	0.202612	0.083183	2.435748	0.0156

R-squared	0.905922	Mean dependent var	1.272962
Adjusted R-squared	0.900069	S.D. dependent var	0.368928
S.E. of regression	0.116625	Akaike info criterion	-1.399238
Sum squared resid	3.060333	Schwarz criterion	-1.181698
Log likelihood	182.9086	Hannan-Quinn criter.	-1.311585
Durbin-Watson stat	2.010275		

Data used for peak period estimation in log form

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
1990	TRS87	1.3013	1.0730	0.4048	0.3961	1.0185	0.6054	0.6114	0.4041	1.0087	1.4535	1.0112	0.9513
1990	NUMRS	14.4242	15.9210	16.2206	15.2533	15.2427	14.6570	15.5148	14.5549	13.5724	13.0339	13.7708	15.9587
1990	QRS_NUMR	-9.8137	-9.8268	-9.5457	-9.6821	-9.9747	-9.9839	-10.1121	-9.8411	-9.9340	-11.0881	-10.1387	-10.2906
1991	TRS87	1.3496	1.1217	0.4383	0.4061	0.9869	0.7178	0.6539	0.4200	0.8813	1.5632	1.0210	1.0692
1991	NUMRS	14.4330	15.9914	16.2352	15.2651	15.2648	14.6832	15.5257	14.5850	13.6744	13.0546	13.8374	15.9747
1991	QRS_NUMR	-9.8481	-9.8694	-9.4866	-9.5907	-9.9350	-9.9281	-10.0510	-9.7635	-9.9330	-11.1596	-10.1994	-10.4037
1992	TRS87	1.3843	1.1746	0.4187	0.4769	1.0595	0.7357	0.6413	0.4536	0.9455	1.5313	0.9832	1.0246
1992	NUMRS	14.4423	16.0036	16.2475	15.2807	15.3133	14.7090	15.5316	14.6128	13.6913	13.0644	13.8095	15.9800
1992	QRS_NUMR	-9.7463	-9.7981	-9.4989	-9.6974	-9.8973	-9.9207	-10.0994	-9.8291	-9.9947	-11.0110	-10.1482	-10.4125
1993	TRS87	1.3820	1.1496	0.4725	0.4174	1.0268	0.6689	0.5867	0.4285	0.9412	1.6365	0.9866	1.0188
1993	NUMRS	14.4511	15.9482	16.2628	15.3088	15.3177	14.7384	15.5461	14.6431	13.7500	13.0915	13.8235	15.9853
1993	QRS_NUMR	-9.7174	-9.6990	-9.4326	-9.5707	-9.8014	-9.8673	-10.0340	-9.7353	-9.8164	-11.1386	-10.1938	-10.3689
1994	TRS87	1.4626	1.2113	0.5602	0.5377	1.0417	0.7789	0.6270	0.3148	1.0047	1.5705	1.0989	1.0644
1994	NUMRS	14.4669	15.9546	16.2793	15.3186	15.3552	14.7660	15.5493	14.6859	13.8117	13.1179	13.8590	15.9927
1994	QRS_NUMR	-9.6833	-9.6305	-9.4214	-9.5819	-9.8242	-9.8557	-10.0686	-9.8535	-9.9180	-11.0983	-10.2387	-10.3976
1995	TRS87	1.4777	1.2395	0.4181	0.5394	1.0357	0.7752	0.6719	0.4867	1.0564	1.5497	1.1641	1.2479
1995	NUMRS	14.4722	15.9635	16.2956	15.3296	15.3786	14.7928	15.5719	14.7298	13.8644	13.1468	13.8953	16.0011
1995	QRS_NUMR	-9.8144	-9.7202	-9.4542	-9.6281	-9.8344	-9.8930	-10.1371	-9.9560	-10.0186	-11.0584	-10.4061	-10.5225
1996	TRS87	1.3476	1.0818	0.1781	0.5158	0.8316	0.3859	0.5277	0.3350	0.9486	1.4764	0.8042	1.0371
1996	NUMRS	14.4787	15.9705	16.3101	15.3458	15.4097	14.8172	15.5827	14.7820	13.9172	13.1648	13.9272	16.0128
1996	QRS_NUMR	-9.7463	-9.6610	-9.3922	-9.5186	-9.7506	-9.8066	-10.0178	-9.8489	-9.8830	-10.9631	-10.3015	-10.5316
1997	TRS87	1.4246	1.2644	0.5200	0.5224	1.0685	0.7789	0.5464	0.2708	0.8759	1.5913	0.8229	0.9658
1997	NUMRS	14.4942	15.9815	16.3246	15.3617	15.4343	14.8403	15.5943	14.8138	13.9636	13.1859	13.9709	16.0228
1997	QRS_NUMR	-9.8196	-9.7484	-9.4966	-9.6504	-9.9177	-9.9457	-10.0575	-9.8098	-9.9762	-11.2669	-10.1617	-10.4781
1998	TRS87	1.4327	1.2917	0.4904	0.6157	0.9988	0.8608	0.7975	0.5630	0.9999	1.6068	0.9482	1.2250
1998	NUMRS	14.4989	15.9974	16.3359	15.3965	15.4742	14.8582	15.6056	14.8560	14.0103	13.2044	14.0129	16.0361
1998	QRS_NUMR	-9.9191	-9.8890	-9.6541	-9.7858	-10.0032	-10.0339	-10.1671	-9.8718	-9.9315	-11.2087	-10.1565	-10.3678
1999	TRS87	1.5129	1.2759	0.4744	0.6043	0.7784	0.8467	0.7095	0.7222	0.9247	1.6374	1.0753	1.1647
1999	NUMRS	14.5139	15.9997	16.3533	15.3897	15.5150	14.8715	15.6069	14.8947	14.0632	13.2297	14.0591	16.0522
1999	QRS_NUMR	-9.9349	-9.7629	-9.5478	-9.7411	-10.0050	-10.0386	-10.3070	-9.9509	-9.9094	-11.3010	-10.3344	-10.3496
2000	TRS87	1.2459	0.9658	0.2874	0.5682	1.0392	0.6611	0.4867	0.4600	0.8809	1.5769	0.8454	1.0239
2000	NUMRS	14.5479	16.0179	16.3707	15.4080	15.5191	14.8989	15.6219	14.9377	14.1061	13.2568	14.0976	16.0564
2000	QRS_NUMR	-9.8027	-9.7135	-9.5247	-9.7105	-9.8176	-9.9435	-10.2082	-9.9300	-9.9268	-11.1472	-10.3574	-10.4820
2001	TRS87	1.1669	0.8359	0.4220	0.5104	0.9910	0.7410	0.6233	0.5086	0.9195	1.6954	0.7993	0.7641
2001	NUMRS	14.5525	16.0404	16.3786	15.4165	15.5482	14.9102	15.6258	14.9727	14.1408	13.2883	14.1309	16.0808
2001	QRS_NUMR	-9.8536	-9.7796	-9.5948	-9.6984	-9.9725	-9.9584	-10.1280	-9.8815	-9.8992	-11.1316	-10.2740	-10.4422
2002	TRS87	1.3252	1.0061	0.1798	0.5499	1.1709	0.9131	0.7894	0.6021	1.3468	1.7721	1.2823	1.0116
2002	NUMRS	14.5638	16.0403	16.3942	15.4318	15.5633	14.9165	15.6392	15.0026	14.1702	13.3108	14.1679	16.0935
2002	QRS_NUMR	-9.9004	-9.8433	-9.6303	-9.9500	-9.9503	-9.9813	-10.1525	-9.8950	-10.0019	-11.2021	-10.3534	-10.5047
2003	TRS87	1.0640	0.9727	0.2343	0.3112	0.9532	0.7328	0.4904	0.2461	0.8771	1.7006	0.9723	0.9677
2003	NUMRS	14.5811	16.0513	16.3998	15.4423	15.5781	14.9256	15.6478	15.0353	14.2350	13.3332	14.1914	16.1013
2003	QRS_NUMR	-9.7270	-9.6751	-9.5145	-9.7046	-9.8285	-9.9254	-10.1285	-9.9871	-10.1089	-11.1387	-10.4292	-10.5824
2004	TRS87	1.4448	1.1049	0.4562	0.5844	1.1471	0.9384	0.7348	0.4769	0.9936	1.8242	1.0512	0.9869
2004	NUMRS	14.5756	16.0534	16.4051	15.4520	15.5898	14.9327	15.6576	15.0708	14.2355	13.3677	14.2230	16.1165

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
2004	QRS_NUMR	-9.8007	-9.7289	-9.5665	-9.7569	-9.8660	-10.0182	-10.2595	-9.9870	-10.0385	-11.2037	-10.3556	-10.5074
2005	TRS87	1.3379	1.0112	0.5253	0.5977	1.1991	1.1059	0.8346	0.6471	1.0996	1.8538	1.0791	1.0613
2005	NUMRS	14.5778	16.0534	16.4355	15.4628	15.6158	14.9387	15.6603	15.1071	14.2811	13.3940	14.2685	16.1330
2005	QRS_NUMR	-9.7550	-9.7055	-9.5980	-9.7940	-9.9176	-10.0749	-10.2975	-10.0114	-10.0741	-11.2697	-10.4966	-10.6082
2006	TRS87	1.4382	1.0702	0.5922	0.7802	1.3712	1.1594	0.9223	0.6719	1.1872	1.9608	1.2392	1.0536
2006	NUMRS	14.6041	16.0667	16.4213	15.4743	15.6183	14.9404	15.6673	15.1360	14.3135	13.4197	14.2995	16.1530
2006	QRS_NUMR	-9.9612	-9.9080	-9.7920	-9.9646	-10.1252	-10.2239	-10.4576	-10.0484	-10.0769	-11.3045	-10.5704	-10.6089
2007	TRS87	1.4864	1.0909	0.4472	0.6683	1.2977	0.9723	0.6249	0.3350	1.3113	1.8413	1.2638	0.9427
2007	NUMRS	14.6116	16.0784	16.4269	15.4747	15.6430	14.9418	15.6896	15.1576	14.3400	13.4342	14.3264	16.1636
2007	QRS_NUMR	-9.8358	-9.7697	-9.6440	-9.8083	-10.0464	-10.1692	-10.2719	-9.9694	-10.0544	-11.4291	-10.4542	-10.5827
2008	TRS87	1.3928	1.1184	0.4855	0.5188	1.2655	0.9639	0.6981	0.2994	1.1499	1.7733	1.1499	0.9547
2008	NUMRS	14.6286	16.0706	16.4277	15.4811	15.6491	14.9374	15.6981	15.1769	14.3588	13.4288	14.3374	16.1708
2008	QRS_NUMR	-9.8906	-9.7897	-9.5915	-9.7199	-10.0515	-10.0780	-10.2801	-9.9503	-10.0494	-11.3525	-10.4683	-10.5638
2009	TRS87	1.6335	1.2695	0.7903	0.8171	1.2355	1.1304	0.9066	0.5545	1.2369	1.9854	1.2550	1.0463
2009	NUMRS	14.5832	16.0687	16.4454	15.4815	15.6506	14.9563	15.6793	15.1583	14.3126	13.4289	14.3197	16.1646
2009	QRS_NUMR	-9.9948	-9.7392	-9.6625	-9.7911	-9.9657	-10.1392	-10.3138	-10.0136	-9.9490	-11.4385	-10.5687	-10.6136

Data used for off-peak period estimation in log form

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
1990	TRS87	1.4572	1.3623	0.7696	0.7120	1.2790	1.0152	1.1575	0.5134	1.2202	1.8083	1.4110	0.9509
1990	NUMRS	14.4242	15.9210	16.2206	15.2533	15.2427	14.6570	15.5148	14.5549	13.5724	13.0339	13.7708	15.9587
1990	QRS_NUMR	-10.1737	-10.1963	-9.9287	-10.1549	-10.4345	-10.4700	-10.5254	-10.1992	-10.3260	-11.2459	-10.7420	-10.5401
1991	TRS87	1.4697	1.3661	0.7622	0.7571	1.2565	1.0811	1.1499	0.5218	1.1378	1.8672	1.3903	1.1285
1991	NUMRS	14.4330	15.9914	16.2352	15.2651	15.2648	14.6832	15.5257	14.5850	13.6744	13.0546	13.8374	15.9747
1991	QRS_NUMR	-10.2129	-10.2794	-9.9370	-10.1508	-10.4257	-10.5158	-10.5282	-10.1586	-10.2602	-11.2210	-10.6974	-10.4672
1992	TRS87	1.3002	1.2934	0.6785	0.7367	1.1210	0.9490	1.1311	0.3660	1.1894	1.8746	1.3697	1.0112
1992	NUMRS	14.4423	16.0036	16.2475	15.2807	15.3133	14.7090	15.5316	14.6128	13.6913	13.0644	13.8095	15.9800
1992	QRS_NUMR	-10.0309	-10.1508	-9.8551	-10.1300	-10.3308	-10.4581	-10.5444	-10.2928	-10.4391	-11.1796	-10.7692	-10.5941
1993	TRS87	1.2436	1.3337	0.8002	0.7756	1.2006	0.9381	1.0325	0.5110	1.0770	1.9327	1.3486	1.0533
1993	NUMRS	14.4511	15.9482	16.2628	15.3088	15.3177	14.7384	15.5461	14.6431	13.7500	13.0915	13.8235	15.9853
1993	QRS_NUMR	-10.0770	-10.1454	-9.8863	-10.0785	-10.3702	-10.4200	-10.4423	-10.1556	-10.2861	-11.1613	-10.7189	-10.5619
1994	TRS87	1.3990	1.5250	0.9030	0.7509	1.3126	1.1703	1.2499	0.5446	1.1378	1.9370	1.3880	1.1716
1994	NUMRS	14.4669	15.9546	16.2793	15.3186	15.3552	14.7660	15.5493	14.6859	13.8117	13.1179	13.8590	15.9927
1994	QRS_NUMR	-10.2330	-10.2089	-10.0332	-10.2796	-10.5232	-10.6547	-10.6284	-10.2230	-10.3182	-11.2742	-10.7146	-10.4615
1995	TRS87	1.3676	1.5059	0.6355	0.7971	1.2447	1.0378	1.2093	0.6871	1.2250	1.9244	1.4344	1.2686
1995	NUMRS	14.4722	15.9635	16.2956	15.3296	15.3786	14.7928	15.5719	14.7298	13.8644	13.1468	13.8953	16.0011
1995	QRS_NUMR	-10.2486	-10.2046	-9.8990	-10.1283	-10.4491	-10.5672	-10.6332	-10.1208	-10.3370	-11.2799	-10.7640	-10.5265
1996	TRS87	1.2179	1.4156	0.7251	0.8011	1.2945	1.0420	1.1490	0.5939	1.0515	1.9081	1.2404	1.1641
1996	NUMRS	14.4787	15.9705	16.3101	15.3458	15.4097	14.8172	15.5827	14.7820	13.9172	13.1648	13.9272	16.0128
1996	QRS_NUMR	-10.1759	-10.0992	-9.8632	-10.1027	-10.3690	-10.4690	-10.5870	-10.1797	-10.2427	-11.1834	-10.7557	-10.5586
1997	TRS87	1.3737	1.2977	0.6896	0.7006	1.3048	1.1594	1.1628	0.7333	0.9636	1.9840	1.4978	1.1817
1997	NUMRS	14.4942	15.9815	16.3246	15.3617	15.4343	14.8403	15.5943	14.8138	13.9636	13.1859	13.9709	16.0228
1997	QRS_NUMR	-10.1844	-10.1359	-9.9058	-10.1853	-10.3817	-10.5536	-10.5969	-10.2171	-10.2644	-11.3449	-10.8543	-10.6133
1998	TRS87	1.3538	1.4852	0.8912	0.9517	1.4389	1.2096	1.3172	0.9817	1.0821	1.9462	1.6148	1.2596
1998	NUMRS	14.4989	15.9974	16.3359	15.3965	15.4742	14.8582	15.6056	14.8560	14.0103	13.2044	14.0129	16.0361
1998	QRS_NUMR	-10.3094	-10.2789	-10.1529	-10.3891	-10.6234	-10.7340	-10.8047	-10.2558	-10.3918	-11.2958	-10.8069	-10.4719
1999	TRS87	1.0889	1.3689	0.7701	0.9219	1.3943	1.1805	1.2698	0.9010	1.0445	1.9481	1.4173	1.0852
1999	NUMRS	14.5139	15.9997	16.3533	15.3897	15.5150	14.8715	15.6069	14.8947	14.0632	13.2297	14.0591	16.0522
1999	QRS_NUMR	-10.2181	-10.2620	-10.1580	-10.3818	-10.6582	-10.7539	-10.8316	-10.2372	-10.2219	-11.2957	-10.7622	-10.4560
2000	TRS87	1.2021	1.1666	0.7641	0.9369	1.2873	1.2075	1.2439	0.7683	1.0360	1.9498	1.0543	1.1401
2000	NUMRS	14.5479	16.0179	16.3707	15.4080	15.5191	14.8989	15.6219	14.9377	14.1061	13.2568	14.0976	16.0564
2000	QRS_NUMR	-10.2939	-10.2010	-10.0886	-10.3475	-10.4772	-10.7147	-10.7695	-10.2952	-10.2961	-11.3271	-10.7458	-10.5203
2001	TRS87	1.5986	1.5336	0.8858	1.1518	1.4931	1.4535	1.3543	1.2768	1.4339	2.1949	1.5484	1.1171
2001	NUMRS	14.5525	16.0404	16.3786	15.4165	15.5482	14.9102	15.6258	14.9727	14.1408	13.2883	14.1309	16.0808
2001	QRS_NUMR	-10.3591	-10.3157	-10.2289	-10.4221	-10.6404	-10.8037	-10.8797	-10.3798	-10.1673	-11.3560	-10.9661	-10.6333
2002	TRS87	1.1783	1.3180	0.4898	0.9135	1.4253	1.3279	1.2407	0.9776	1.3118	2.0916	1.6413	1.0325
2002	NUMRS	14.5638	16.0403	16.3942	15.4318	15.5633	14.9165	15.6392	15.0026	14.1702	13.3108	14.1679	16.0935
2002	QRS_NUMR	-10.2894	-10.2494	-10.0372	-10.4213	-10.5565	-10.7848	-10.8196	-10.2990	-10.3072	-11.3809	-11.0132	-10.5959
2003	TRS87	1.6186	1.5151	0.9115	1.0726	1.5988	1.4413	1.5072	0.9738	1.0335	2.2077	1.6160	1.0526
2003	NUMRS	14.5811	16.0513	16.3998	15.4423	15.5781	14.9256	15.6478	15.0353	14.2350	13.3332	14.1914	16.1013
2003	QRS_NUMR	-10.2544	-10.2498	-10.1390	-10.4069	-10.6046	-10.8938	-10.9634	-10.3580	-10.3962	-11.4032	-10.9974	-10.5834
2004	TRS87	1.4646	1.4598	0.8796	1.1230	1.6372	1.4839	1.5330	0.9555	1.1681	2.1940	1.6409	0.9058
2004	NUMRS	14.5756	16.0534	16.4051	15.4520	15.5898	14.9327	15.6576	15.0708	14.2355	13.3677	14.2230	16.1165
2004	QRS_NUMR	-10.3369	-10.3011	-10.2379	-10.5061	-10.6721	-10.9527	-10.9803	-10.3803	-10.4749	-11.3955	-11.0150	-10.6372
2005	TRS87	1.2565	1.3067	0.8920	1.0574	1.5239	1.4063	1.5061	0.9768	1.1534	2.0852	1.4960	0.9310

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
2005	NUMRS	14.5778	16.0534	16.4355	15.4628	15.6158	14.9387	15.6603	15.1071	14.2811	13.3940	14.2685	16.1330
2005	QRS_NUMR	-10.3301	-10.3133	-10.2901	-10.5292	-10.6477	-10.8541	-10.9974	-10.4205	-10.4464	-11.3454	-11.0278	-10.6804
2006	TRS87	1.5839	1.4591	0.9431	1.1597	1.7837	1.5063	1.6380	0.8924	1.4159	2.2101	1.8361	1.1429
2006	NUMRS	14.6041	16.0667	16.4213	15.4743	15.6183	14.9404	15.6673	15.1360	14.3135	13.4197	14.2995	16.1530
2006	QRS_NUMR	-10.4060	-10.4084	-10.2527	-10.5223	-10.6889	-10.9109	-11.0536	-10.4466	-10.4555	-11.4250	-11.0867	-10.6868
2007	TRS87	1.5611	1.4748	1.0919	1.3310	1.7778	1.4913	1.5573	0.9662	1.4900	2.1891	1.8070	1.1891
2007	NUMRS	14.6116	16.0784	16.4269	15.4747	15.6430	14.9418	15.6896	15.1576	14.3400	13.4342	14.3264	16.1636
2007	QRS_NUMR	-10.3719	-10.3408	-10.3127	-10.5771	-10.6998	-10.9956	-11.0435	-10.4942	-10.4203	-11.4010	-11.1591	-10.7360
2008	TRS87	1.4298	1.4639	1.2161	1.2273	1.6152	1.4734	1.4704	0.7659	0.9869	2.0844	1.8111	1.2459
2008	NUMRS	14.6286	16.0706	16.4277	15.4811	15.6491	14.9374	15.6981	15.1769	14.3588	13.4288	14.3374	16.1708
2008	QRS_NUMR	-10.3753	-10.3351	-10.2613	-10.4774	-10.6242	-10.8958	-11.0306	-10.4334	-10.3485	-11.3981	-11.1367	-10.7886
2009	TRS87	1.7502	1.6044	1.1547	1.2444	1.8710	1.6198	1.6156	0.9761	1.5667	2.3046	1.8086	1.1597
2009	NUMRS	14.5832	16.0687	16.4454	15.4815	15.6506	14.9563	15.6793	15.1583	14.3126	13.4289	14.3197	16.1646
2009	QRS_NUMR	-10.4626	-10.3705	-10.2891	-10.5011	-10.7517	-10.9740	-10.9774	-10.3727	-10.3909	-11.4718	-11.0855	-10.7547

Table F7

Data: Equation for commercial distribution tariffs

Author: Ernest Zampelli, SAIC, with Ben Laughlin, EIA Intern, 2010.

Source: The source for the peak and off-peak data used in this estimation was the *Natural Gas Monthly*, DOE/EIA-0130. State level city gate and commercial prices by month were averaged using quantity-weights to arrive at seasonal (peak and off-peak), regional level (12 NGTDM regions) prices. The quantity-weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. Historical commercial floorspace data by census division were extracted from the NEMS model and allocated to NGTDM region using Census population figures.

Variables:

$TCM_{r,n,t}$ = commercial distributor tariff in region r, network n (1987 dollars per Mcf) [DTAR_SF2]

REG_r = 1, if observation is in region r, =0 otherwise

$QCM_FLR_{r,n,t}$ = commercial gas consumption per floorspace for region r in year t (Bcf) [(BASQTY_SF2+BASQTY_SI2)/FLRSPC12]

$FLR_{r,t}$ = commercial floorspace for region r in year t (estimated in thousand square feet) [FLRSPC12]

r = NGTDM region

n = network (1=peak, 2=off-peak)

t = year

$\alpha_{r,n}$ = estimated parameters for regional dummy variables [PCMREGPK13]

$\beta_{1,n}$,$\beta_{2,n}$ = estimated parameters

ρ_n = autocorrelation coefficient

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The commercial distributor tariff equation was estimated using panel data for the 12 NGTDM regions over the 1990 to 2009 time period. The equation was estimated in log-linear form with corrections for cross sectional heteroscedasticity and first order serial correlation using EViews. The form of the estimated equation follows:

$$\ln TCM_{r,n,t} = \sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QCM_FLR_{r,n,t} + \beta_{2,n} * \ln FLR_{r,t} +$$
$$\rho_n * \ln TCM_{r,n,t-1} - \rho_n * (\sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QCM_FLR_{r,n,t-1} + \beta_{2,n} * \ln NUMCM_{r,t-1})$$

Regression Diagnostics and Parameter Estimates for the Peak Period

Dependent Variable: LNTCM87
Method: Least Squares
Date: 07/23/10 Time: 08:03
Sample (adjusted): 2 240
Included observations: 239 after adjustments
Convergence achieved after 9 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=4)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQCM_FLR	-0.217322	0.129951	-1.672341	0.0959
LNFLR	0.218189	0.121009	1.803081	0.0727
REGION=1	-4.498378	1.340720	-3.355196	0.0009
REGION=2	-4.852790	1.408476	-3.445420	0.0007
REGION=3	-5.471895	1.435476	-3.811903	0.0002
REGION=4	-5.266668	1.364229	-3.860545	0.0001
REGION=5	-5.054427	1.410819	-3.582619	0.0004
REGION=6	-4.975067	1.349163	-3.687521	0.0003
REGION=7	-5.517942	1.406269	-3.923816	0.0001
REGION=8	-5.253175	1.305366	-4.024293	0.0001
REGION=9	-4.795673	1.307829	-3.666896	0.0003
REGION=10	-5.051970	1.397162	-3.615881	0.0004
REGION=11	-4.899262	1.299003	-3.771555	0.0002
REGION=12	-4.817270	1.405236	-3.428085	0.0007
AR(1)	0.284608	0.083893	3.392527	0.0008

R-squared	0.809134	Mean dependent var	0.594811
Adjusted R-squared	0.797204	S.D. dependent var	0.347177
S.E. of regression	0.156344	Akaike info criterion	-0.812814
Sum squared resid	5.475313	Schwarz criterion	-0.594626
Log likelihood	112.1313	Hannan-Quinn criter.	-0.724890
Durbin-Watson stat	1.979180		

Regression Diagnostics and Parameter Estimates for the Off-Peak Period

Dependent Variable: LNTCM87
Method: Least Squares
Date: 07/23/10 Time: 08:04
Sample: 241 480
Included observations: 240
Convergence achieved after 6 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=4)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQCM_FLRSPC	-0.613588	0.209576	-2.927752	0.0038
LNFLRSPC	0.530831	0.213552	2.485719	0.0137
REGION=1	-13.87098	1.869814	-7.418373	0.0000
REGION=2	-14.12193	2.052895	-6.879033	0.0000
REGION=3	-14.49560	2.085660	-6.950127	0.0000
REGION=4	-14.29389	1.944700	-7.350175	0.0000
REGION=5	-14.37939	2.005218	-7.170990	0.0000
REGION=6	-13.98336	1.889625	-7.400073	0.0000

REGION=7	-14.50539	2.000913	-7.249384	0.0000
REGION=8	-13.81237	1.894236	-7.291790	0.0000
REGION=9	-13.71773	1.813711	-7.563346	0.0000
REGION=10	-14.29647	1.877570	-7.614347	0.0000
REGION=11	-13.50724	1.778116	-7.596376	0.0000
REGION=12	-14.05762	2.001953	-7.021954	0.0000
AR(1)	0.166956	0.091737	1.819954	0.0701

R-squared	0.603286	Mean dependent var	0.577749
Adjusted R-squared	0.578601	S.D. dependent var	0.335016
S.E. of regression	0.217477	Akaike info criterion	-0.152989
Sum squared resid	10.64162	Schwarz criterion	0.064551
Log likelihood	33.35864	Hannan-Quinn criter.	-0.065336
Durbin-Watson stat	1.997625		

Data used for peak period estimation in log form

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
1990	TCM87	1.03354	0.782073	0.14842	0.042101	0.696143	0.430483	0.206201	0.028587	0.679555	0.735248	0.541161	0.904218
1990	QCM_FLR	-10.80819	-10.27518	-10.02571	-10.0121	-10.87259	-10.66464	-10.6939	-10.05054	-10.88697	-12.19567	-10.64772	-10.65706
1990	FLR	14.73416	15.69451	15.92281	15.07962	15.5246	14.82673	15.50667	14.31229	14.34193	14.8613	13.94832	15.48136
1991	TCM87	1.008688	0.80245	0.200489	0.090754	0.643432	0.518198	0.224742	0.058269	0.615186	0.76314	0.578297	1.0654
1991	QCM_FLR	-10.78194	-10.22102	-9.971767	-9.929256	-10.76971	-10.60622	-10.60989	-9.986422	-10.86598	-12.15423	-10.671	-10.80858
1991	FLR	14.74157	15.70491	15.93733	15.09204	15.55072	14.84239	15.51601	14.33424	14.36901	14.88742	13.97028	15.50845
1992	TCM87	1.074661	0.861201	0.193921	0.170586	0.711478	0.563608	0.322083	0.08526	0.658556	0.709021	0.549277	1.072268
1992	QCM_FLR	-10.67296	-10.15695	-9.984192	-10.02488	-10.69684	-10.61159	-10.66214	-10.05214	-10.96197	-12.10189	-10.66952	-10.77438
1992	FLR	14.74724	15.71275	15.94971	15.10304	15.57115	14.85401	15.52609	14.35083	14.38809	14.90785	13.98686	15.52753
1993	TCM87	1.017041	0.82242	0.265436	0.131905	0.680062	0.514618	0.288931	0.130151	0.625404	0.920283	0.581657	1.135587
1993	QCM_FLR	-10.61099	-10.14154	-9.926096	-9.900956	-10.64854	-10.54903	-10.68735	-9.946373	-10.76914	-12.1597	-10.7212	-10.84729
1993	FLR	14.75353	15.71675	15.96006	15.1135	15.58787	14.86603	15.53845	14.36863	14.40303	14.92458	14.00466	15.54246
1994	TCM87	1.17619	0.949339	0.377751	0.309688	0.710004	0.648673	0.266969	-0.037702	0.720762	0.729961	0.702602	1.439124
1994	QCM_FLR	-10.35558	-10.09798	-9.894967	-9.90904	-10.65618	-10.51963	-10.67386	-10.01784	-10.85795	-12.16941	-10.77524	-10.88982
1994	FLR	14.75796	15.72214	15.97161	15.12337	15.60436	14.88037	15.55029	14.39101	14.41575	14.94106	14.02705	15.55519
1995	TCM87	1.130434	0.950885	0.228728	0.249201	0.708036	0.628075	0.276115	0.18648	0.783445	0.727065	0.781616	1.382788
1995	QCM_FLR	-10.43041	-10.10463	-9.908138	-9.943346	-10.64013	-10.52523	-10.63409	-10.10654	-10.91288	-12.16089	-10.87959	-10.88643
1995	FLR	14.76406	15.72657	15.98518	15.1362	15.6225	14.89741	15.56682	14.41638	14.42795	14.9592	14.05242	15.56738
1996	TCM87	0.984697	0.874218	-0.04919	0.27079	0.548121	0.135405	0.138892	-0.019183	0.64815	0.639219	0.322808	1.107572
1996	QCM_FLR	-10.34278	-9.983987	-9.842353	-9.848968	-10.62702	-10.44972	-10.65972	-10.0069	-10.77339	-12.14789	-10.81071	-11.03641
1996	FLR	14.77156	15.73278	15.99937	15.15122	15.6444	14.91814	15.58439	14.44409	14.44094	14.98111	14.08013	15.58038
1997	TCM87	1.108893	0.927428	0.336472	0.222343	0.738598	0.559616	0.195567	-0.139262	0.475613	0.667316	0.360468	1.096276
1997	QCM_FLR	-10.30902	-10.00031	-9.948278	-9.98826	-10.68835	-10.55067	-10.5866	-9.999211	-10.86226	-12.31262	-10.71917	-10.94718
1997	FLR	14.78041	15.73888	16.01425	15.16549	15.6683	14.9417	15.60114	14.47542	14.45301	15.00501	14.11146	15.59244
1998	TCM87	1.06264	0.691646	0.300845	0.277632	0.718327	0.675492	0.447247	0.275356	0.617345	0.823298	0.609222	1.234308
1998	QCM_FLR	-10.39582	-9.992437	-10.09763	-10.06498	-10.71608	-10.66425	-10.75371	-10.09564	-10.80522	-12.32806	-10.73728	-10.96726
1998	FLR	14.79058	15.74669	16.03036	15.1816	15.69627	14.96628	15.62199	14.50829	14.46986	15.03297	14.14433	15.60929
1999	TCM87	1.021371	0.608678	0.291176	0.29565	0.561899	0.642906	0.280657	0.464363	0.58389	0.822859	0.687632	1.094604
1999	QCM_FLR	-10.59798	-9.933422	-10.01313	-10.06831	-10.72396	-10.66884	-10.76822	-10.20156	-10.74532	-12.35381	-10.84215	-10.95635
1999	FLR	14.80814	15.7567	16.04907	15.20068	15.72808	14.99202	15.64769	14.55063	14.49341	15.06479	14.18667	15.63284
2000	TCM87	0.813593	1.010509	0.002996	0.24686	0.687129	0.403463	-0.115411	0.111541	0.594431	0.690143	0.144966	0.967744
2000	QCM_FLR	-10.52122	-9.982545	-9.976626	-10.04653	-10.673	-10.60803	-10.71636	-10.16844	-10.7873	-12.1577	-10.87075	-11.04346
2000	FLR	14.82306	15.76907	16.06954	15.22189	15.76349	15.01802	15.67919	14.59011	14.51777	15.10019	14.22614	15.65721
2001	TCM87	0.740985	0.905432	0.128393	0.191446	0.771034	0.570414	-0.071496	0.242946	0.535908	1.127524	0.222343	0.726582
2001	QCM_FLR	-10.5722	-10.07162	-10.03531	-10.04857	-10.79009	-10.65373	-10.74992	-10.12952	-10.76708	-12.16264	-10.87023	-11.06204
2001	FLR	14.84233	15.78239	16.08961	15.2449	15.79681	15.04719	15.70677	14.6275	14.54296	15.13352	14.26353	15.6824
2002	TCM87	0.995102	0.442118	0.1415	0.203757	0.764072	0.731887	0.350657	0.360468	1.055705	1.118742	0.911479	0.885419
2002	QCM_FLR	-10.63463	-10.05163	-10.1255	-10.27543	-10.77561	-10.70046	-10.66041	-10.1548	-10.89604	-12.07748	-10.91055	-11.1448
2002	FLR	14.86432	15.79755	16.10825	15.26372	15.82963	15.0726	15.73421	14.66104	14.56744	15.16634	14.29707	15.70687
2003	TCM87	0.735728	0.82154	-0.043952	-0.009041	0.517006	0.508623	0.024693	-0.149661	0.515813	1.028547	0.442761	0.789366
2003	QCM_FLR	-10.60418	-9.934664	-9.984421	-10.07127	-10.73325	-10.63397	-10.67996	-10.25794	-10.94268	-12.1272	-10.99802	-11.08346
2003	FLR	14.87915	15.81076	16.124	15.28423	15.8558	15.09277	15.75895	14.68954	14.58792	15.1925	14.32557	15.72736
2004	TCM87	1.160334	0.913487	0.180653	0.280657	0.752359	0.666803	0.349952	0.094401	0.834213	1.166582	0.519984	0.799757
2004	QCM_FLR	-10.65883	-9.927092	-10.04934	-10.10882	-10.72775	-10.70777	-10.79844	-10.24872	-10.90133	-12.10691	-10.9337	-11.14323
2004	FLR	14.8915	15.82207	16.13839	15.30039	15.88185	15.11195	15.78199	14.71552	14.60498	15.21855	14.35156	15.74441
2005	TCM87	1.066433	0.756122	0.198031	0.318454	0.733329	0.942738	0.486738	0.366724	0.740985	1.011964	0.555608	0.914689
2005	QCM_FLR	-10.65271	-10.03913	-10.07135	-10.17298	-10.75486	-10.78261	-10.93415	-10.27977	-10.90604	-12.12498	-11.03518	-11.20321
2005	FLR	14.90435	15.83166	16.15338	15.31553	15.90631	15.13114	15.80292	14.74137	14.62178	15.24301	14.37741	15.76122
2006	TCM87	1.111199	0.781158	0.364643	0.509224	0.94585	0.92267	0.485508	0.423305	0.945461	1.307792	0.771034	0.947789
2006	QCM_FLR	-10.80154	-10.20122	-10.25512	-10.32185	-10.91544	-10.88917	-11.06584	-10.31421	-10.89834	-12.28774	-11.06119	-11.18639
2006	FLR	14.92068	15.84244	16.17045	15.33077	15.93231	15.15151	15.82449	14.7725	14.63929	15.26902	14.40853	15.77872
2007	TCM87	1.20627	0.597737	0.206201	0.408128	0.905028	0.699626	0.105261	0.038259	1.04486	1.032116	0.782988	0.732368
2007	QCM_FLR	-10.64449	-10.08287	-10.14895	-10.20875	-10.86095	-10.87075	-10.94939	-10.26239	-10.87505	-12.31859	-11.02282	-11.12961
2007	FLR	14.93262	15.85366	16.18633	15.34587	15.95991	15.1722	15.84616	14.80524	14.65694	15.29661	14.44127	15.79638
2008	TCM87	1.045212	0.580538	0.099845	0.245296	0.81978	0.683602	0.142367	-0.042908	0.821101	1.002101	0.560758	0.797958
2008	QCM_FLR	-10.70065	-10.08087	-10.08169	-10.10907	-10.88544	-10.82181	-10.96436	-10.25204	-10.86054	-12.33066	-11.05978	-11.13563

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
2008	FLR	14.946	15.86429	16.20345	15.36096	15.98527	15.19212	15.87062	14.83697	14.67404	15.32198	14.473	15.81347
2009	TCM87	1.185096	0.609222	0.404798	0.444686	0.78527	0.897719	0.447886	0.214305	0.950499	1.03176	0.65752	0.783445
2009	QCM_FLR	-10.72952	-10.06608	-10.12776	-10.18844	-10.85652	-10.88899	-10.99863	-10.33785	-10.83499	-12.34896	-11.17492	-11.19006
2009	FLR	14.95814	15.87473	16.21753	15.37525	16.00654	15.20937	15.88914	14.86197	14.68849	15.34324	14.49801	15.82793

Data used for off-peak period estimation in log form

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
1990	TCM87	0.81978	0.711969	0.379805	-0.177931	0.630207	0.528862	0.183155	-0.185125	0.738121	0.738121	0.564177	0.534151
1990	QCM_FLR	-10.90124	-10.34489	-10.31414	-10.18253	-10.96697	-10.85666	-10.5901	-10.29073	-11.02909	-11.77349	-10.73081	-10.38875
1990	FLR	14.73416	15.69451	15.92281	15.07962	15.5246	14.82673	15.50667	14.31229	14.34193	14.8613	13.94832	15.48136
1991	TCM87	0.818016	0.702602	0.413433	-0.080126	0.578858	0.560758	0.221542	-0.176737	0.702602	0.730443	0.666803	0.728514
1991	QCM_FLR	-10.9393	-10.37896	-10.37715	-10.1497	-10.89713	-10.89184	-10.59688	-10.25007	-10.93988	-11.7143	-10.73172	-10.31648
1991	FLR	14.74157	15.70491	15.93733	15.09204	15.55072	14.84239	15.51601	14.33424	14.36901	14.88742	13.97028	15.50845
1992	TCM87	0.513422	0.700123	0.262364	-0.125563	0.429832	0.430483	0.087095	-0.55687	0.782073	0.693147	0.491031	0.436318
1992	QCM_FLR	-10.7426	-10.30278	-10.2948	-10.18815	-10.82841	-10.83675	-10.55567	-10.36185	-11.10669	-11.68164	-10.67683	-10.38468
1992	FLR	14.74724	15.71275	15.94971	15.10304	15.57115	14.85401	15.52609	14.35083	14.38809	14.90785	13.98686	15.52753
1993	TCM87	0.14842	0.671924	0.438255	0.059212	0.506215	0.442761	0.132781	-0.125563	0.677526	0.946238	0.567584	0.850151
1993	QCM_FLR	-10.76579	-10.33389	-10.30689	-10.20689	-10.84683	-10.79649	-10.57541	-10.22038	-11.00829	-11.6948	-10.64436	-10.5797
1993	FLR	14.75353	15.71675	15.96006	15.1135	15.58787	14.86603	15.53845	14.36863	14.40303	14.92458	14.00466	15.54246
1994	TCM87	0.365337	0.90987	0.555608	-0.142716	0.559044	0.620576	0.367417	-0.015114	0.703098	0.845439	0.733329	1.214022
1994	QCM_FLR	-10.57619	-10.34363	-10.38704	-10.28376	-10.88405	-10.89237	-10.6291	-10.23104	-10.98642	-11.76509	-10.68369	-10.49269
1994	FLR	14.75796	15.72214	15.97161	15.12337	15.60436	14.88037	15.55029	14.39101	14.41575	14.94106	14.02705	15.55519
1995	TCM87	0.436318	0.880456	0.265436	0.051643	0.555034	0.525911	0.170586	0.276115	0.815365	0.727065	0.758935	1.09293
1995	QCM_FLR	-10.55041	-10.25587	-10.26514	-10.18332	-10.83986	-10.85856	-10.48104	-10.1478	-10.98213	-11.78257	-10.71065	-10.41359
1995	FLR	14.76406	15.72657	15.98518	15.1362	15.6225	14.89741	15.56682	14.41638	14.42795	14.9592	14.05242	15.56738
1996	TCM87	0.249201	0.760338	0.35977	0.07139	0.596085	0.65024	0.157858	0.025668	0.590561	0.832474	0.407463	0.910675
1996	QCM_FLR	-10.42864	-10.23423	-10.23524	-10.16125	-10.79765	-10.7675	-10.6159	-10.19003	-10.89767	-11.76986	-10.70743	-10.61657
1996	FLR	14.77156	15.73278	15.99937	15.15122	15.6444	14.91814	15.58439	14.44409	14.44094	14.98111	14.08013	15.58038
1997	TCM87	0.528273	0.00995	0.335043	-0.191161	0.695644	0.690143	0.358374	0.178146	0.483043	0.875885	0.522359	0.909468
1997	QCM_FLR	-10.32009	-9.960956	-10.25067	-10.28505	-10.78882	-10.73029	-10.48983	-10.22183	-10.87255	-11.91702	-10.78638	-10.5713
1997	FLR	14.78041	15.73888	16.01425	15.16549	15.6683	14.9417	15.60114	14.47542	14.45301	15.00501	14.11146	15.59244
1998	TCM87	0.385262	0.413433	0.524729	0.175633	0.744315	0.607044	0.510426	0.574364	0.617885	0.809151	0.828115	1.053615
1998	QCM_FLR	-10.47149	-10.05141	-10.4248	-10.4753	-10.83441	-10.90459	-10.71362	-10.26044	-10.98847	-11.91034	-10.78333	-10.41553
1998	FLR	14.79058	15.74669	16.03036	15.1816	15.69627	14.96628	15.62199	14.50829	14.46986	15.03297	14.14433	15.60929
1999	TCM87	-0.357674	0.32573	-0.375693	-0.036332	-0.640274	-0.603769	-0.41871	-0.502592	-0.576051	-0.82022	-0.599386	-0.945073
1999	QCM_FLR	10.5712	9.960255	10.44113	10.47538	10.90767	10.88557	10.76356	10.30853	10.88778	12.00961	10.78357	10.69796
1999	FLR	-14.80814	-15.7567	-16.04907	-15.20068	-15.72808	-14.99202	-15.64769	-14.55063	-14.49341	-15.06479	-14.18667	-15.63284
2000	TCM87	-0.209487	-0.500875	0.370183	0.173953	0.585005	0.626473	0.235072	0.237441	0.323532	0.661657	0.157004	0.856116
2000	QCM_FLR	-10.64719	-9.928819	-10.38156	-10.45832	-10.87819	-10.97466	-10.67225	-10.32453	-10.89739	-11.73493	-10.80875	-10.6644
2000	FLR	14.82306	15.76907	16.06954	15.22189	15.76349	15.01802	15.67919	14.59011	14.51777	15.10019	14.22614	15.65721
2001	TCM87	0.731406	0.951272	0.576051	0.491031	0.907855	0.963937	0.452985	1.003202	1.0936	1.363026	0.74479	0.817133
2001	QCM_FLR	-10.75139	-10.03607	-10.51336	-10.54833	-10.92828	-11.03404	-10.86342	-10.44685	-10.81949	-11.73978	-10.91398	-10.69869
2001	FLR	14.84233	15.78239	16.08961	15.2449	15.79681	15.04719	15.70677	14.6275	14.54296	15.13352	14.26353	15.6824
2002	TCM87	0.274597	0.290428	0.260825	0.303063	0.662688	0.824175	0.306749	0.540579	0.836381	1.101608	0.853564	0.605408
2002	QCM_FLR	-10.69804	-9.993283	-10.3539	-10.51929	-10.95871	-11.03534	-10.62712	-10.39477	-11.01604	-11.64437	-10.9786	-10.73535
2002	FLR	14.86432	15.79755	16.10825	15.26372	15.82963	15.0726	15.73421	14.66104	14.56744	15.16634	14.29707	15.70687
2003	TCM87	1.125579	0.783445	0.50742	0.407463	0.793897	0.764537	0.682592	0.541161	0.463734	1.20147	0.724646	0.72222
2003	QCM_FLR	-10.81744	-10.1338	-10.46123	-10.54033	-10.94377	-11.05512	-10.73289	-10.43014	-11.01381	-11.70079	-10.98742	-10.85435
2003	FLR	14.87915	15.81076	16.124	15.28423	15.8558	15.09277	15.75895	14.68954	14.58792	15.1925	14.32557	15.72736
2004	TCM87	0.826366	0.740508	0.386622	0.363948	0.710004	0.814479	0.650761	0.490419	0.78982	1.18142	0.762207	0.394067
2004	QCM_FLR	-10.95466	-10.09444	-10.51966	-10.58474	-10.97447	-11.05178	-10.85089	-10.47832	-11.07644	-11.69623	-11.01532	-10.84808
2004	FLR	14.8915	15.82207	16.13839	15.30039	15.88185	15.11195	15.78199	14.71552	14.60498	15.21855	14.35156	15.74441
2005	TCM87	0.592774	0.527093	0.255417	0.180653	0.463734	0.789366	0.541161	0.444045	0.519984	0.941569	0.456792	0.432432
2005	QCM_FLR	-10.98257	-10.26062	-10.56394	-10.64246	-10.98874	-11.04146	-10.96842	-10.46439	-11.03032	-11.68515	-11.05266	-10.82296
2005	FLR	14.90435	15.83166	16.15338	15.31553	15.90631	15.13114	15.80292	14.74137	14.62178	15.24301	14.37741	15.76122
2006	TCM87	0.993622	0.35347	0.404131	0.408128	1.02029	0.916291	0.787548	0.463734	1.059178	1.178039	1.137512	0.795704
2006	QCM_FLR	-11.02975	-10.27795	-10.52172	-10.61187	-11.00399	-11.10895	-11.03871	-10.49775	-11.02842	-11.83787	-11.08461	-10.78475
2006	FLR	14.92068	15.84244	16.17045	15.33077	15.93231	15.15151	15.82449	14.7725	14.63929	15.26902	14.40853	15.77872
2007	TCM87	0.947789	0.405465	0.552159	0.579418	0.841998	0.852712	0.614104	0.594983	1.112186	1.178963	1.042042	0.792993
2007	QCM_FLR	-10.95062	-10.22291	-10.57512	-10.66478	-11.02575	-11.14991	-11.02351	-10.57283	-10.9986	-11.84828	-11.14366	-10.8093
2007	FLR	14.93262	15.85366	16.18633	15.34587	15.95991	15.1722	15.84616	14.80524	14.65694	15.29661	14.44127	15.79638
2008	TCM87	0.863312	0.539413	0.779325	0.496524	0.636577	0.909065	0.30822	0.239017	0.279146	1.082483	1.0431	0.923068
2008	QCM_FLR	-10.97875	-10.23502	-10.54087	-10.56937	-10.98552	-11.13943	-10.98381	-10.51688	-10.95221	-11.88835	-11.1648	-10.83484
2008	FLR	14.946	15.86429	16.20345	15.36096	15.98527	15.19212	15.87062	14.83697	14.67404	15.32198	14.473	15.81347
2009	TCM87	1.102272	0.518198	0.387301	0.436318	1.070213	1.057443	0.848012	0.623261	1.21075	1.154047	1.091588	0.718815
2009	QCM_FLR	-11.06186	-10.26981	-10.53377	-10.60598	-11.07528	-11.17901	-10.98755	-10.53441	-11.04401	-11.92348	-11.15915	-10.84407
2009	FLR	14.95814	15.87473	16.21753	15.37525	16.00654	15.20937	15.88914	14.86197	14.68849	15.34324	14.49801	15.82793

Table F8

Data: Equation for electric generator distribution tariffs or markups.

Author: Ernest Zampelli, SAIC, 2008.

Source: The original source for the natural gas prices to electric generators used with city gate prices to calculate markups was the *Electric Power Monthly*, DOE/EIA-0226. The original source for the rest of the data used was the *Natural Gas Monthly*, DOE/EIA-0130. State level city gate and electric generator prices by month were averaged using quantity-weights to arrive at seasonal (peak and off-peak), regional level (12 NGTDM and 16 NGTDM/EMM regions, respectively) prices. The quantity-weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. The consumption data were generated within the historical routines in the NEMS system based on state level data from the original source and therefore may differ from the original source.

Variables:

$MARKUP_{r,t}$ = electric generator distributor tariff (or markup) in region r, year t (1987 dollars per Mcf) [UDTAR_SF]

$QELEC_{r,t}$ = electric generator consumption of natural gas [sum of BASUQTY_SF and BASUQTY_SI]

REG_r = 1, if observation is in region r, =0 otherwise

$\beta_{0.r}$ = coefficient on REGr [PELREG20 or PELREG25 equivalent to the product of REGr and β0r]

β_0, β_1 = Estimated parameters

ρ = autocorrelation coefficient

r = NGTDM/EMM region

t = year

n = season (1=peak, 2=off-peak)

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and/or in the model code.]

Derivation: The equation used for the peak and off-peak electric markups was estimated using panel data for the 16 EMM regions over the 1990 to 2009 time period and two periods. The equations were estimated in linear form allowing for region and period-specific intercepts and with corrections for cross sectional heteroscedasticity and first order serial correlation using EViews. Because the reported point estimates of the parameters yielded projections of the electric generator distributor tariffs that were considered inconsistent with analyst's expectations (i.e., that did not align well with more recent historical levels), the constant term in each equation was increased by one half of a standard deviation of the error, well within the 95% confidence interval limits for the parameters.

$$MARKUP_{n,r,t} = \beta_{0,n} + \sum_{r} \beta_{0,n,r} REG_{r} + \beta_{1,n} QELEC_{n,r,t} + \rho * MARKUP_{n,r,t-1}$$
$$- \rho_{n} * (\beta_{0,n} + \sum_{r} \beta_{0,n,r} REG_{r} + \beta_{1,n} QELEC_{n,r,t-1})$$

Regression Diagnostics and Parameter Estimates

This table reports the results of the estimation of the electric generator tariff equation allowing for different intercepts for each region/peak and off-peak period pairing.

Dependent Variable: TEU87
Method: Least Squares
Date: 08/03/10 Time: 08:58
Sample (adjusted): 2 640
Included observations: 639 after adjustments
Convergence achieved after 6 iterations
Newey-West HAC Standard Errors & Covariance (lag truncation=6)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.153777	0.059859	-2.569001	0.0104
R1N1	-0.569051	0.187530	-3.034454	0.0025
R1N2	-1.377838	0.165891	-8.305701	0.0000
R2N2	-0.836857	0.142380	-5.877619	0.0000
R4N1	-0.993607	0.123113	-8.070659	0.0000
R4N2	-0.966333	0.122853	-7.865788	0.0000
R5N2	-0.553732	0.118913	-4.656614	0.0000
R6N2	-0.549285	0.066117	-8.307780	0.0000
R7N2	-0.495265	0.150436	-3.292203	0.0011
R9N2	-0.349100	0.143640	-2.430379	0.0154
R10N1	-0.453206	0.099193	-4.568931	0.0000
R10N2	-0.625117	0.089210	-7.007262	0.0000
R11N1	-0.553142	0.115808	-4.776368	0.0000
R11N2	-1.148493	0.338392	-3.393968	0.0007
QELEC	7.04E-07	2.61E-07	2.703306	0.0071
AR(1), ρ	0.281378	0.048877	5.756867	0.0000

R-squared	0.337021	Mean dependent var	-0.341534
Adjusted R-squared	0.321059	S.D. dependent var	0.704578
S.E. of regression	0.580558	Akaike info criterion	1.775065
Sum squared resid	209.9805	Schwarz criterion	1.886738
Log likelihood	-551.1334	Hannan-Quinn criter.	1.818414
F-statistic	21.11324	Durbin-Watson stat	2.010879
Prob(F-statistic)	0.000000		

Data used for estimation

YEAR	REG	TEU87 peak	QELEC peak	TEU87 off-peak	QELEC off-peak	REG	TEU87 peak	QELEC peak	TEU87 off-peak	QELEC off-peak
1990	1	-0.373	5477.792	-0.689	78029.21	9	0.202	112.733	-0.07	733.267
1991	1	-0.285	10403.05	-0.948	90079.95	9	-0.07	88	-1.004	350
1992	1	-0.431	4216.713	-0.879	124801.3	9	-0.031	85	-0.434	474
1993	1	-0.595	16036.8	-1.384	109778.2	9	-0.079	54	-1.686	1745
1994	1	-0.626	11368.83	-1.836	146989.2	9	0.061	118.826	-1.354	1249.174

YEAR	REG	TEU87	QELEC	TEU87	QELEC	REG	TEU87	QELEC	TEU87	QELEC
1995	1	-0.898	30834.64	-1.78	164613.4	9	0.142	380.87	-0.344	2539.13
1996	1	-0.544	30441.67	-1.507	152519.3	9	-0.009	471.804	-0.227	1934.196
1997	1	-0.647	51998.01	-0.985	152213	9	-0.044	478.75	-0.447	3349.25
1998	1	-0.527	58556.68	-1.476	124108.3	9	0.343	644.785	-0.557	11348.22
1999	1	-2.145	26046.15	-2.22	154448.8	9	-0.129	904	-0.324	10655
2000	1	-2.864	48405.54	-2.915	151491.4	9	-0.248	2628.278	0.356	6823.722
2001	1	-0.25	75437.73	-1.985	192119.3	9	-0.921	655.664	-0.514	6254.336
2002	1	-0.665	106724.8	-1.482	233054.2	9	-0.82	4669.191	-0.453	11638.81
2003	1	-0.218	93391.41	-0.622	249761.6	9	0.321	2993.909	-0.332	6293.09
2004	1	0.075	104596.4	-1.357	248623.6	9	-0.117	1886.401	-0.005	5208.599
2005	1	0.103	96665.48	-0.938	258176.5	9	0.616	5315.032	-0.031	17492.97
2006	1	-1.356	101914.5	-1.654	267822.5	9	-0.905	3080.886	-0.662	15897.11
2007	1	-0.079	103940.7	-1.287	277224.3	9	-0.312	6110.758	-0.597	20556.24
2008	1	0.252	101929.7	-0.739	250712.3	9	-0.071	4028.149	0.085	9966.851
2009	1	-0.906	113848.8	-1.615	238725.2	9	-1.09	3550.858	-0.92	8518.142
1990	2	-0.091	56008.69	-0.827	254571.3	10	-0.78	11836.17	-0.971	58827.83
1991	2	-0.157	64743.73	-0.898	267021.3	10	-0.812	15655.99	-1.021	51891.01
1992	2	-0.277	86805.72	-0.846	297436.3	10	-0.931	16384.83	-0.943	42633.17
1993	2	-0.302	83314.7	-0.87	308035.3	10	-0.715	8031.323	-0.744	38079.68
1994	2	-0.503	70013.87	-0.815	393282.2	10	-0.56	16516.63	-0.983	71653.38
1995	2	-0.444	134962.2	-0.675	487430.7	10	-0.607	30614.88	-0.86	89503.12
1996	2	0.171	62217.58	-0.622	411604.4	10	0.692	14569.8	-0.618	76325.2
1997	2	-0.502	111473	-1.339	456865	10	-0.684	14076	-0.592	70928
1998	2	-0.397	108447	-0.742	433440	10	-0.615	15754.85	-0.793	88350.15
1999	2	-0.284	108384.3	-0.864	496415.8	10	-0.541	28160.57	-0.566	103466.4
2000	2	0.037	120397.1	-0.692	408934.9	10	-0.559	34598.51	-0.28	108258.5
2001	2	0.566	114874.5	-0.896	393543.5	10	-1.737	40322.03	-1.047	177977
2002	2	-0.56	140725.3	-0.283	435593.6	10	-0.807	79041.83	-0.438	197026.2
2003	2	0.591	111812	-0.135	320290	10	0.211	58740.21	-0.426	123469.8
2004	2	0.17	121153.9	-0.097	354346.2	10	-0.434	59686.33	-0.333	164801.7
2005	2	0.356	116582	0.151	393216	10	0.674	56009.41	0.03	184339.6
2006	2	-0.916	137123.6	-1.023	482526.4	10	-1.223	46339.27	-0.933	239106.8
2007	2	-0.366	171300.2	-0.902	538288.8	10	-0.589	82203.64	-0.851	276528.3
2008	2	0.118	189873.8	-0.029	520375.2	10	-0.307	95446.84	-0.201	236164.2
2009	2	-1.209	212035.5	-1.426	544876.5	10	-1.263	121736.6	-1.046	292033.4
1990	3	0.477	150	-0.356	1103	11	-0.5	383955.5	-0.588	1244416
1991	3	-0.539	453	-0.68	2784	11	-0.471	381862.6	-0.474	1224830
1992	3	-0.597	933	-0.9	2023	11	-0.4	396487	-0.439	1151983
1993	3	-0.491	1267	0.237	1469	11	-0.39	381623.1	-0.41	1254746
1994	3	1.015	845.443	0.864	2122.557	11	-0.384	386224	-0.37	1266091
1995	3	-0.197	851.772	-0.584	6606.229	11	-0.555	426659.9	-0.507	1298862
1996	3	0.336	446.384	-0.27	2455.616	11	-0.183	387316.8	-0.302	1250172
1997	3	0.397	390	-0.063	3100	11	-0.628	378754.8	-0.27	1292336
1998	3	0.447	904.887	0.156	7075.113	11	-0.241	393644.6	-0.113	1588856
1999	3	0.282	2043.821	-0.556	9343.18	11	-0.407	449100.1	-0.214	1535106
2000	3	-0.057	2424.521	0.069	7697.479	11	-0.173	505656.9	-0.106	1587056
2001	3	1.586	1313.623	2.199	9230.377	11	-0.469	473726.6	-0.291	1475389
2002	3	-0.291	5156.494	-0.457	17565.51	11	-0.5	527764.5	-0.314	1583531
2003	3	-0.134	5862.449	0.086	12911.55	11	0.169	520349.9	0.035	1422995
2004	3	-0.037	5929.066	-0.26	12328.93	11	-0.229	496203.2	-0.024	1383611
2005	3	0.204	6165.703	-0.088	21775.3	11	0.066	497927.9	-0.046	1544522
2006	3	-0.931	4535.418	-0.126	18648.58	11	-0.645	474470.1	-0.286	1534773
2007	3	-0.287	9500.535	-0.174	27791.47	11	-0.524	541641.6	-0.532	1506612
2008	3	0.267	8165.851	1.186	15327.15	11	-0.454	571748.9	-0.527	1451966

YEAR	REG	TEU87	QELEC	TEU87	QELEC	REG	TEU87	QELEC	TEU87	QELEC
2009	3	-0.925	12502.88	-1.185	25454.13	11	-1.02	550137.3	-0.832	1434106
1990	4	-1.817	31429.56	-1.347	72129.44	12	-0.595	108.33	-0.957	376.67
1991	4	-1.348	31578.48	-1.253	77733.52	12	0.711	74.782	1.56	268.218
1992	4	-1.418	44851.64	-1.497	68893.36	12	1.405	51.828	-0.004	250.172
1993	4	-1.241	35502.96	-1.283	87438.03	12	0.845	112.683	0.455	242.317
1994	4	-0.907	45192.25	-1.022	104732.8	12	-0.713	189.751	-0.878	571.249
1995	4	-1.128	47723.8	-1.258	132765.2	12	5.098	93.277	1.118	422.723
1996	4	-1.342	41181.18	-1.264	136386.8	12	3.806	267.156	1.572	471.844
1997	4	-1.893	58116.89	-1.709	149975.1	12	-1.3	713.689	-0.673	1580.311
1998	4	-1.426	57722.75	-1.106	185009.2	12	-0.003	834	-1.099	1726
1999	4	-1.017	56206.06	-1.275	181599.9	12	-1.421	661.7	-1.291	1543.3
2000	4	-0.795	62974.71	-0.843	154818.3	12	-1.468	858	-1.035	2886
2001	4	-1.38	55546.81	-0.777	164441.2	12	-0.705	2966.774	-0.578	10398.23
2002	4	-0.447	64369.93	-0.624	219275	12	0.762	1841.396	0.58	4757.604
2003	4	-0.951	58171.08	-0.766	128116.9	12	-0.093	3115.147	-0.2	9223.853
2004	4	-1.009	67560.77	-1.245	140486.2	12	-0.73	3432.394	-0.513	9186.606
2005	4	-1.006	62452.09	-1.464	220560.9	12	-0.394	3310.012	-0.31	8903.987
2006	4	-1.683	43653.99	-0.841	179495	12	-0.645	2908.668	-0.985	8073.332
2007	4	-0.72	70883.59	-0.594	207352.4	12	-0.109	4028.414	-0.17	11499.59
2008	4	-0.447	70728.65	0.307	132756.4	12	0.074	4134.663	0.213	9996.337
2009	4	-0.718	63267.38	-1.036	128803.6	12	-0.835	3748.62	-0.598	9380.38
1990	5	-0.591	6513.661	-0.868	37663.33	13	-0.406	7475.622	-1.168	30674.38
1991	5	-0.577	8386.246	-0.945	54605.75	13	-0.725	8442.727	-1.35	32877.27
1992	5	-0.477	6564.392	-0.855	19551.61	13	-0.779	11631.35	-1.39	41860.65
1993	5	-0.404	5430.949	-0.708	31682.05	13	-0.202	16816.29	-0.642	41179.71
1994	5	-0.379	6607.164	-1.018	37455.84	13	-0.624	16133.88	-1.112	66494.13
1995	5	-0.49	9284.483	-0.854	48442.52	13	-0.717	25685.17	-0.801	67311.83
1996	5	-0.145	6701.926	-0.869	33308.07	13	-0.188	22187.69	-0.468	78930.31
1997	5	-0.485	7062.148	-1.058	40882.85	13	-0.467	22608.37	-0.311	83926.64
1998	5	-0.275	6673.499	-0.839	73116.5	13	-0.385	28588.31	0.006	94087.7
1999	5	-0.392	11064.86	-0.741	67943.15	13	-0.072	35234.71	-0.007	102074.3
2000	5	-0.33	14452.84	-0.533	73293.16	13	1.265	53316.27	0.455	141533.7
2001	5	-0.658	12855.91	-0.609	68365.09	13	1.211	71984.5	1.291	137618.5
2002	5	-0.502	14525.6	-0.627	61418.4	13	0.473	56705.46	0.332	146509.5
2003	5	0.365	12441.34	-0.24	51685.66	13	0.415	52597.99	0.28	155741
2004	5	0.111	15715.84	-0.398	45414.16	13	-0.132	62488.94	0.094	167248.1
2005	5	0.574	22234.67	-0.68	82644.33	13	0.01	68457.95	0.123	184153
2006	5	-0.07	16733.13	-0.368	93896.87	13	-0.452	76476.9	-0.827	212270.1
2007	5	0.162	36287.14	-0.307	106214.9	13	-0.652	91240.94	-0.624	260458.1
2008	5	0.254	40233.62	-0.079	81822.38	13	-0.092	100212.7	0.03	242283.3
2009	5	-0.488	30968.19	-0.602	68794.81	13	-0.614	101870	-0.415	254915
1990	6	0.123	5736.463	-0.57	45691.54	14	-0.12	12451.51	-0.552	37300.48
1991	6	-0.259	9603.718	-0.824	55953.28	14	-0.39	10503.82	-0.595	40932.18
1992	6	-0.1	13896.39	-0.568	40156.62	14	-0.093	11060.75	-0.151	42418.25
1993	6	-0.168	18359.31	-0.714	46145.68	14	0.047	11955.11	-0.095	36309.89
1994	6	-0.247	18000.7	-0.969	60320.31	14	-0.143	13658.88	-0.164	44792.13
1995	6	-0.142	25663.08	-0.677	78174.92	14	-0.125	13662.47	-0.176	40548.53
1996	6	-0.021	14490.55	-0.611	57460.45	14	0.394	11768.99	0.121	45934.01
1997	6	-0.455	11760.21	-0.704	48107.79	14	0.084	12934.19	-0.122	54012.81
1998	6	-0.031	10607.77	-0.703	82748.23	14	0.076	18095.38	-0.132	69705.62
1999	6	-0.088	18558	-0.702	88756	14	-0.042	22906.24	-0.124	74796.77
2000	6	-0.661	18429.81	-0.196	77524.2	14	0.368	33129.53	0.148	109635.5
2001	6	1.04	11727.8	-0.54	83846.2	14	0.489	49709.35	-0.107	128357.6
2002	6	-0.542	31719.6	-1.034	113421.4	14	0.286	50972.55	-0.266	131697.5

YEAR	REG	TEU87	QELEC	TEU87	QELEC	REG	TEU87	QELEC	TEU87	QELEC
2003	6	0.025	22153.38	-0.48	65724.62	14	0.355	52509.88	0.372	155480.1
2004	6	-0.342	31824.06	-0.621	96166.94	14	0.239	73750.1	0.265	197387.9
2005	6	-0.163	42401.81	-0.379	132210.2	14	0.716	70105.91	0.66	188586.1
2006	6	-1.163	38068.46	-0.523	135358.5	14	-0.245	80424.6	-0.312	223227.4
2007	6	-0.056	50933.98	-0.522	170925	14	-0.019	88519	-0.567	252688
2008	6	0.475	47926.71	-0.042	144152.3	14	-0.166	103157.1	0.523	249401.9
2009	6	-1.173	60839.04	-0.951	177359	14	-0.482	95551.13	-0.231	239102.9
1990	7	0.373	94	-0.127	1838	15	-0.398	2163.144	-0.413	5411.857
1991	7	0.18	86	-0.214	752	15	-0.111	2385.528	-0.415	10360.47
1992	7	0.599	40	-0.404	1122	15	-0.184	6807.541	0.497	19222.46
1993	7	0.601	112.963	-0.408	2913.037	15	0.499	26265.15	-0.027	18996.85
1994	7	0.485	268.321	-0.153	1070.679	15	-0.333	26457.18	-0.207	42886.82
1995	7	1.584	368.214	-0.26	10727.79	15	-0.285	17894.08	-0.113	41866.93
1996	7	1.371	208.809	-0.706	5566.191	15	0.58	1662.173	-0.161	66420.83
1997	7	0.181	323.943	-0.941	16729.06	15	0.104	7462.426	0.902	44431.57
1998	7	-1.064	845	-0.463	32505	15	-0.372	16440.47	-0.323	76776.53
1999	7	-0.867	683	-1.1	31822	15	-0.098	12471.85	-0.158	69827.15
2000	7	0.814	676	-0.777	41357	15	0.166	30435.15	0.56	113414.9
2001	7	-0.394	1813.314	-1.357	32851.69	15	0.213	55816.64	0.531	112908.4
2002	7	-0.472	12366.93	-0.961	44221.07	15	-0.439	30135.98	-0.949	65269.01
2003	7	-0.114	8131.998	-0.605	24126	15	-0.518	41637.16	-1.075	90642.84
2004	7	-0.437	11419.18	-0.718	34506.82	15	-0.675	46265.81	-0.82	108536.2
2005	7	0.062	17548.92	-0.107	54718.08	15	-0.387	48284.78	-0.701	105522.2
2006	7	-1.522	20942.52	-0.854	74464.48	15	-1.054	36728.14	-1.325	97256.86
2007	7	-0.527	27945.63	-0.963	93780.37	15	-0.7	45077.4	-0.962	113719.6
2008	7	0.218	24032.35	-0.327	72283.65	15	-0.536	62191.23	-0.708	129025.8
2009	7	-1.494	36520.59	-1.208	106465.4	15	-1.093	61018.65	-1.443	133252.4
1990	8	-0.111	53532.49	-0.081	135631.5	16	0.519	154426.4	0.106	474358.6
1991	8	-0.347	57488.14	-0.233	143844.9	16	0.314	200566.8	0.049	427968.1
1992	8	-0.559	54243.96	-0.149	149075	16	0.129	227147.9	0.029	535783.1
1993	8	-0.41	47776.24	-0.304	140451.8	16	0.261	244498.6	0.09	428566.4
1994	8	-0.538	53104.2	-0.412	158386.8	16	-0.027	238089.7	0.013	572584.3
1995	8	-0.384	80269.09	-0.369	289028.9	16	0.403	181126.9	0.103	421776.1
1996	8	-0.203	70158.84	-0.441	267108.2	16	0.446	116542	0.08	408493
1997	8	-1.335	88892.73	-0.917	249964.3	16	0.344	129870	0.036	465952
1998	8	-0.996	80991.75	-0.831	242778.3	16	0.378	206154	0.294	442932
1999	8	-0.436	83337	-0.25	282249	16	0.305	279871.4	0.035	443299.6
2000	8	-0.699	109654.3	-0.233	254590.7	16	3.086	234992	0.621	658384
2001	8	-0.608	88541.95	-0.013	285769.1	16	1.745	313453.9	1.712	659873.1
2002	8	0.223	114050.8	0.133	407817.2	16	0.606	229522.8	0.335	497104.2
2003	8	0.241	134894.4	0.056	400204.6	16	0.438	222017.6	0.166	483325.4
2004	8	-0.203	145665.3	0.002	440175.8	16	0.003	230285.1	-0.041	540231.9
2005	8	-0.598	153085.3	-0.367	477324.7	16	0.559	216351.5	-0.172	472817.5
2006	8	-0.21	162821.4	0.462	578937.6	16	-0.409	211302.6	0.249	559533.4
2007	8	0.835	177456.6	0.931	595511.4	16	0.046	236827.2	-0.076	597458.9
2008	8	0.396	198930.3	0.309	598335.6	16	0.092	279011.8	0.08	578855.2
2009	8	1.253	232426	1.368	677572	16	0.123	255257.8	0.146	557431.3

Table F9

Data: Equation for natural gas price at the Henry Hub

Author: Eddie Thomas, EI-83, 2008

Source: Annual natural gas wellhead prices and chain-type GDP price deflators data from EIA's *Annual Energy Review 2007*, DOE/EIA-0384(2007), published June 2008. Henry Hub spot price data from EIA's Short-Term Energy Outlook database series NGHHUUS; the annual Henry Hub prices equal the arithmetic average of the monthly data.

Variables:

HHPRICE	=	Henry Hub spot natural gas price (1987 dollars per MMBtu)
EIAPRICE	=	Average U.S. natural gas wellhead price (1987 dollars per Mcf)
HHPRICE_HAT	=	estimated values for Henry Hub price (1987 dollars per MMBtu)
α	=	estimated parameter
α_0	=	constant term
const2	=	constant term

Derivation: Using TSP version 5.0 and annual price data from 1995 through 2007, the first equation was estimated in log-linear form using ordinary least squares. The second equation estimates an adjustment factor that is applied in cases where the value of "y" is predicted from an estimated equation where the dependent variable is the natural log of y. The adjustment is due to the fact that generally predictions of "y" using the first equation only tend to be biased downward.

1) $\ln HHPRICE = \alpha_0 + (\alpha * \ln EIAPRICE)$
2) $HHPRICE = \beta * HHPRICE_HAT$

Regression Diagnostics and Parameter Estimates

First Equation

Dependent variable: lnHHPRICE
Current sample: 1 to 13
Number of observations: 13

Mean of dep. var.	= 1.00473	LM het. test	= .317007 [.573]
Std. dev. of dep. var.	= .447616	Durbin-Watson	= 2.74129 [<.934]
Sum of squared residuals	= .048856	Jarque-Bera test	= .475878 [.788]
Variance of residuals	= .444143E-02	Ramsey's RESET2	= .103879 [.754]
Std. error of regression	= .066644	F (zero slopes)	= 530.339 [.000]
R-squared	= .979680	Schwarz B.I.C.	= -15.2838
Adjusted R-squared	= .977833	Log likelihood	= 17.8487

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value	Symbol
CONST	.090246	.043801	2.06036	[.064]	α_0
lnEIAPRICE	1.00119	.043475	23.0291	[.000]	α

Second Equation

Dependent variable: HHPRICE
Current sample: 1 to 13
Number of observations: 13

Mean of dep. var.	= 2.98879	LM het. test	= 2.14305 [.143]
Std. dev. of dep. var.	= 1.29996	Durbin-Watson	= 2.97238 [<1.00]
Sum of squared residuals	= .420043	Jarque-Bera test	= .138664 [.933]
Variance of residuals	= .035004	Ramsey's RESET2	= .655186 [.435]
Std. error of regression	= .187092	Schwarz B.I.C.	= -2.58158
R-squared	= .979456	Log likelihood	= 3.86405
Adjusted R-squared	= .979456		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value	Symbol
HHPRICE_HAT	1.00439	.016114	62.3290	[.000]	β

Data used for Estimation:

Year	Henry Hub Spot Natural Gas Price ($/MMBtu, in 1987 dollars)	Average U.S. Wellhead Natural Gas Price ($/Mcf, in 1987 dollars)
1995	1.34	1.23
1996	2.14	1.70
1997	1.91	1.79
1998	1.58	1.50
1999	1.70	1.65
2000	3.16	2.73
2001	2.83	2.89
2002	2.36	2.09
2003	3.77	3.40
2004	3.95	3.68
2005	5.62	4.79
2006	4.23	4.03
2007	4.26	3.90

Table F10

Data: Lease and plant fuel consumption in Alaska

Author: Margaret Leddy, EIA summer intern

Source: EIA's Petroleum Supply Annual and Natural Gas Annual.

Variables:

LSE_PLT = Lease and plant fuel consumption in Alaska [QALK_LAP_N]
OIL_PROD = Oil production in Alaska (thousand barrels) [OGPRCOAK]
[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: Using EViews and annual price data from 1981 through 2007, the following equation was estimated using ordinary least squares without a constant term:

$$LSE_PLT_t = \beta_{-1} * LSE_PLT_{t-1} + \beta_1 * OIL_PROD_t$$

The intent was to find an equation that demonstrated similar characteristics to the projection by the Alaska Department of Natural Resources in their "Alaska Oil and Gas Report."

Regression Diagnostics and Parameter Estimates

Dependent Variable: LSE_PLT
Method: Least Squares
Date: 07/24/09 Time: 17:34
Sample (adjusted): 1981 2007
Included observations: 27 after adjustments

	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
OIL_PROD	0.038873	0.015357	2.531280	0.0180	β_1
LSE_PLT_PREV	0.943884	0.037324	25.28876	0.0000	β_{-1}

R-squared	0.911327	Mean dependent var	210731.2
Adjusted R-squared	0.907780	S.D. dependent var	86703.97
S.E. of regression	26329.98	Akaike info criterion	23.26599
Sum squared resid	1.73E+10	Schwarz criterion	23.36198
Log likelihood	-312.0909	Hannan-Quinn criter.	23.29453
Durbin-Watson stat	2.407017		

Data used for Estimation:

Year	oil_prod	lse_plt	Year	oil_prod	lse_plt	Year	oil_prod	lse_plt
1981	587337	15249	1990	647309	193875	1999	383199	265504.375
1982	618910	94232	1991	656349	223194.366	2000	355199	269177.988
1983	625527	97828	1992	627322	234716.225	2001	351411	271448.841
1984	630401	111069	1993	577495	237701.556	2002	359335	285476.659
1985	666233	64148	1994	568951	238156.064	2003	355582	300463.487
1986	681310	72686	1995	541654	292810.594	2004	332465	281546.298
1987	715955	116682	1996	509999	295833.863	2005	315420	303215.128
1988	738143	153670	1997	472949	271284.345	2006	270486	257091.267
1989	683979	192239	1998	428850	281871.556	2007	263595	268571.098

Table F11

Data: Western Canada successful conventional gas wells

Author: Ernie Zampelli, SAIC, 2009

Source: Canadian Association of Petroleum Producers, Statistical Handbook. Undiscovered remaining resource estimates from National Energy Board of Canada.

Variables:

GWELLS = Number of successful new natural gas wells drilled in Western Canada [SUCWELL]

PGAS2000 = Average natural gas wellhead price in Alberta (2000 U.S. dollars per Mcf) [CN_PRC00]

REMAIN = Remaining natural gas undiscovered resources in Western Canada (Bcf) [URRCAN]

DRILLCOSTPERGASWELL2000 = U.S. based proxy for drilling cost per gas well (2000 U.S. dollars) [CST_PRXYLAG]

PR_LAG = Production to reserve ratio last forecast year [CURPRRCAN]

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: Using TSP version 5.0 and annual price data from 1978 through 2005, the following equation was estimated after taking natural logs of all of the variables and by instrumental variables:

$$\ln GWELLS = \beta_0 + \beta_1 * \ln PGAS2000 + \beta_2 * \ln REMAIN + \beta_3 * \ln DRILLCOSTPERGASWELL2000LAG + \beta_4 * PR_LAG$$

Regression Diagnostics and Parameter Estimates

```
TSP Program File:  canada10_wells_v1.tsp
TSP Output File:  canada10_wells_v1.out
Data File: canada10.xls

Method of estimation = Instrumental Variable

 Dependent variable: LNGWELLS
 Endogenous variables: LNPGAS2000
 Included exogenous variables: C LNREMAIN PR_LAG LNDRILLCOSTPERGASWELL2000LAG
 Excluded exogenous variables: LNRIGS_AVAIL LNRIGS_ACT LNWOP2000
                               LNWOP2000(-1)
 Current sample:  32 to 59
 Number of observations:  28

        Mean of dep. var. = 8.22053  Adjusted R-squared = .868002
   Std. dev. of dep. var. = .770092       Durbin-Watson = 1.47006 [<.460]
 Sum of squared residuals = 1.81489     F (zero slopes) = 44.8913 [.000]
    Variance of residuals = .078908  F (over-id. rest.) = 3.04299 [.049]
 Std. error of regression = .280906             E'PZ*E = .720351
               R-squared = .887557
```

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value	Symbol
C	-1.85639	10.8399	-.171256	[.864]	β_0
LNPGAS2000	1.09939	.275848	3.98551	[.000]	β_1
LNREMAIN	1.57373	.767550	2.05033	[.040]	β_2
PR_LAG	33.6237	5.95568	5.64564	[.000]	β_3
LNDRILLCOSTPERGASWELL2000LAG	-.860630	.413101	-2.08334	[.037]	β_4

where LNGWELLS is the natural log of the number of successful gas wells drilled, C is the constant term, LNPGAS2000 is the natural log of the natural gas wellhead price in US$2000, LNREMAIN is the natural log of remaining natural gas resources, PR_LAG is the one-year lag of the natural gas production to reserves ratio, and LNDRILLCOSTPERGASWELL2000LAG is the one-year lag of the natural log drilling costs per gas well in US$2000.

Data used for Estimation:

OBS	Year	gwells	pgas2000	Remain	drillcostpergaswell2000
3	1949		0.048973961		
4	1950		0.326113924		
5	1951		0.332526561		
6	1952		0.53466758		
7	1953		0.520772302		
8	1954		0.518522266		
9	1955	168	0.508917468		
10	1956	180	0.506220324		
11	1957	194	0.521861883		
12	1958	200	0.481073325		
13	1959	302	0.452683617		
14	1960	292	0.474693506		487885.5568
15	1961	392	0.533594173		445149.9201
16	1962	331	0.529535218		450150.6792
17	1963	338	0.569702785		423745.2977
18	1964	308	0.58367073	247614.5688	473327.0074
19	1965	320	0.567907929	238537.3503	452030.1753
20	1966	342	0.576547139	236436.2237	577347.2558
21	1967	372	0.562604404	232547.9993	590110.0741
22	1968	478	0.537960863	229480.2528	596222.8555
23	1969	524	0.505967348	224686.5834	590148.7629
24	1970	731	0.518371638	219742.8184	583504.0314
25	1971	838	0.506420538	215141.3928	576188.9938
26	1972	1164	0.514557299	211401.9226	522986.1433
27	1973	1656	0.532790308	210506.5381	487525.511
28	1974	1902	0.791608407	207750.6318	544786.1771
29	1975	2080	1.411738215	207326.7494	689458.4496
30	1976	3304	2.237940881	203831.3434	672641.5564
31	1977	3192	2.599391226	201592.1585	733387.9117
32	1978	3319	2.626329384	196792.3469	817752.475
33	1979	3450	2.710346999	191501.0181	894243.9654
34	1980	4241	3.384567857	185756.1549	992546.6758
35	1981	3206	3.221572826	182757.9141	1181643.803
36	1982	2555	3.213342789	177773.8365	1377862.449
37	1983	1374	3.284911566	175254.2284	932534.8506
38	1984	1866	3.129580432	172207.6619	723979.0112
39	1985	2528	2.783743697	164103.9115	729665.916
40	1986	1298	2.102135277	163082.6472	733903.1579
41	1987	1599	1.70904727	162025.2004	519637.6851
42	1988	2300	1.605152553	161045.0253	608099.7173
43	1989	2313	1.6374231	159296.4045	582756.2503
44	1990	2226	1.616410647	154195.8722	577621.032
45	1991	1645	1.413315563	150493.0434	599894.6047
46	1992	908	1.302240063	147472.6695	493273.1377
47	1993	3327	1.450352061	144605.8153	589678.7771
48	1994	5333	1.51784337	141039.5975	592881.5963
49	1995	3325	1.094686059	137038.8014	683668.8164
50	1996	3664	1.255799796	130554.9327	656352.5551
51	1997	4820	1.46778215	128082.3795	763619.5946
52	1998	4955	1.340424158	126038.0859	845430.7986
53	1999	7005	1.702885108	122364.2737	815784.5261
54	2000	9034	3.139760843	117371.83	756939
55	2001	10693	3.517434005	112428.7004	875486.0887
56	2002	9011	2.374637309	105719.0529	951999.7696
57	2003	12911	4.216469412	100440.0085	1039434.608
58	2004	15041	4.506654918	95800	1568071.111
59	2005	15895	6.175733625	89650.7047	1324919.051
60	2006	13850	3.555109614	82089.6695	1161087.791
61	2007	9626	5.155666777	75854.5886	3260771.516
62	2008	8104	6.102395678	69930.7064	

Table F12

Data: Western Canada conventional natural gas finding rate

Author: Ernie Zampelli, SAIC, 2009

Source: Canadian Association of Petroleum Producers, Statistical Handbook. Undiscovered remaining resource estimates from National Energy Board of Canada.

Variables:

FR = Natural gas proved reserves added per successful natural gas well in Western Canada (Bcf/well) [FRCAN]

REMAIN = Remaining natural gas undiscovered resources in Western Canada (Bcf) [URRCAN]

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The equation to project the average natural gas finding rate in Western Canada was estimated for the time period 1965-2007 using TSP version 5.0 and aggregated reserves and production data for the provinces in Western Canada. Natural logs were taken of all data before the estimation was performed. The following equation was estimated with correction for first-order serial correlation:

$$\ln FR_t = \beta_0 + \beta_1 * \ln REMAIN_t + \rho * \ln FR_{t-1} - \rho * (\beta_0 + \beta_1 * \ln REMAIN_{t-1})$$

Regression Diagnostics and Parameter Estimates

```
TSP Program File:  canada10_findrate_v1.tsp
TSP Output File:  canada10_findrate_v1.out
Data File:  canada10.xls

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

 Objective function:  Exact ML (keep first obs.)

 CONVERGENCE ACHIEVED AFTER   6 ITERATIONS

 Dependent variable: LNFR
 Current sample:  19 to 61
 Number of observations:  43
        Mean of dep. var. = .258333           R-squared = .523925
   Std. dev. of dep. var. = 1.01511  Adjusted R-squared = .500121
 Sum of squared residuals = 20.6112       Durbin-Watson = 2.19910
    Variance of residuals = .515280      Schwarz B.I.C. = 50.8486
 Std. error of regression = .717830      Log likelihood = -45.2068

                          Standard
 Parameter  Estimate        Error       t-statistic   P-value     Symbol
 C          -25.3204      6.81740       -3.71409      [.000]      β0
 LNREMAIN   2.13897       .569561       3.75547       [.000]      β1
 RHO (ρ)    .428588       .139084       3.08150       [.002]      ρ
```

Data used for Estimation:

OBS	Year	fr	remain
17	1963	9.28880858	
18	1964	29.47148864	247614.5688
19	1965	6.566020625	238537.3503
20	1966	11.36907719	236436.2237
21	1967	8.246630376	232547.9993
22	1968	10.02859707	229480.2528
23	1969	9.434666031	224686.5834
24	1970	6.294699863	219742.8184
25	1971	4.46237494	215141.3928
26	1972	0.76923067	211401.9226
27	1973	1.664194626	210506.5381
28	1974	0.222861409	207750.6318
29	1975	1.680483654	207326.7494
30	1976	0.677719401	203831.3434
31	1977	1.503700376	201592.1585
32	1978	1.594253932	196792.3469
33	1979	1.665177739	191501.0181
34	1980	0.706965527	185756.1549
35	1981	1.554609357	182757.9141
36	1982	0.986147984	177773.8365
37	1983	2.217297307	175254.2284
38	1984	4.342845874	172207.6619
39	1985	0.403981131	164103.9115
40	1986	0.81467396	163082.6472
41	1987	0.612992558	162025.2004
42	1988	0.760269913	161045.0253
43	1989	2.205158798	159296.4045
44	1990	1.663445103	154195.8722
45	1991	1.836093556	150493.0434
46	1992	3.157328414	147472.6695
47	1993	1.071901954	144605.8153
48	1994	0.750196156	141039.5975
49	1995	1.950035699	137038.8014
50	1996	0.674823472	130554.9327
51	1997	0.424127303	128082.3795
52	1998	0.741435358	126038.0859
53	1999	0.712697173	122364.2737
54	2000	0.547169537	117371.83
55	2001	0.627480361	112428.7004
56	2002	0.585844457	105719.0529
57	2003	0.35938413	100440.0085
58	2004	0.408835536	95800
59	2005	0.475686392	89650.7047
60	2006	0.450186347	82089.6695
61	2007	0.615404342	75854.5886
62	2008		69930.7064

Table F13

Data: Western Canada production-to-reserves ratio

Author: Ernie Zampelli, SAIC, 2009

Source: Canadian Association of Petroleum Producers, Statistical Handbook.

Variables:

PR = Natural gas production-to-reserve ratio in Western Canada [PRRATCAN]

GWELLS = Number of successful new natural gas wells drilled in Western Canada [SUCWELL}

RES_ADD_PER_WELL = Proved natural gas reserves added per successful natural gas well in Western Canada (Bcf/well) [FRCAN]

YEAR = Calendar year [RLYR]

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The equation was estimated using TSP version 5.0 for the period from 1978 to 2007 using aggregated data in natural log form (with the exception of YEAR) for the provinces of Western Canada. Because the PR ratio is bounded between zero and one, the dependent variable was measured in logistic form, as follows:

$$\ln\left(\frac{PR_t}{1-PR_t}\right) = \beta_0 + \beta_1 * \ln GWELLS_t + \beta_2 * \ln RES_ADD_PER_WELL_t + \beta_3 * YEAR + \rho * \ln\left(\frac{PR_{t-1}}{1-PR_{t-1}}\right) - \rho * (\beta_0 + \beta_1 * \ln GWELLS_t + \beta_2 * \ln RES_ADD_PER_WELL_t + \beta_3 * YEAR)$$

Regression Diagnostics and Parameter Estimates

```
TSP Program File:  canada10_pr_v1.tsp
TSP Output File:  canada10_pr_v1.out
Data File:  canada10.xls

FIRST-ORDER SERIAL CORRELATION OF THE ERROR

 Objective function:  Exact ML (keep first obs.)

 CONVERGENCE ACHIEVED AFTER   7 ITERATIONS

 Dependent variable: LOGISTIC
 Current sample:  32 to 61
 Number of observations:  30
```

```
      Mean of dep. var. = -2.68213              R-squared = .986473
  Std. dev. of dep. var. = .479351       Adjusted R-squared = .984308
Sum of squared residuals = .090398            Durbin-Watson = 1.29483
   Variance of residuals = .361591E-02      Schwarz B.I.C. = -35.3745
Std. error of regression = .060132          Log likelihood = 43.8775
```

Parameter	Estimate	Standard Error	t-statistic	P-value	Symbol
C	-72.1364	13.7385	-5.25069	[.000]	β_0
LNGWELLS	.117911	.032053	3.67858	[.000]	β_1
LNRES_ADD_PER_WELL	.041469	.017819	2.32723	[.020]	β_2
YEAR	.034370	.690795E-02	4.97536	[.000]	β_3
RHO (ρ)	.916835	.061397	14.9329	[.000]	ρ

Data used for Estimation:

OBS	Year	pr	gwells	res_add_per_well
9	1955		168	
10	1956		180	
11	1957		194	
12	1958		200	
13	1959		302	
14	1960		292	
15	1961		392	
16	1962		331	
17	1963	0.023779341	338	9.28880858
18	1964	0.024979017	308	29.47148864
19	1965	0.022612325	320	6.566020625
20	1966	0.02372014	342	11.36907719
21	1967	0.024985242	372	8.246630376
22	1968	0.027431524	478	10.02859707
23	1969	0.030312333	524	9.434666031
24	1970	0.032625343	731	6.294699863
25	1971	0.034308623	838	4.46237494
26	1972	0.037697554	1164	0.76923067
27	1973	0.041418124	1656	1.664194626
28	1974	0.040851176	1902	0.222861409
29	1975	0.042823468	2080	1.680483654
30	1976	0.042727689	3304	0.677719401
31	1977	0.04464118	3192	1.503700376
32	1978	0.04178307	3319	1.594253932
33	1979	0.042644059	3450	1.665177739
34	1980	0.037495598	4241	0.706965527
35	1981	0.036757207	3206	1.554609357
36	1982	0.036329357	2555	0.986147984
37	1983	0.034484267	1374	2.217297307
38	1984	0.03717602	1866	4.342845874
39	1985	0.038172848	2528	0.403981131
40	1986	0.035340517	1298	0.81467396
41	1987	0.039250307	1599	0.612992558
42	1988	0.046730172	2300	0.760269913
43	1989	0.051076089	2313	2.205158798
44	1990	0.050410254	2226	1.663445103
45	1991	0.054586093	1645	1.836093556
46	1992	0.060679876	908	3.157328414
47	1993	0.068904777	3327	1.071901954
48	1994	0.075709817	5333	0.750196156
49	1995	0.080323276	3325	1.950035699
50	1996	0.082543421	3664	0.674823472
51	1997	0.087979875	4820	0.424127303
52	1998	0.095582952	4955	0.741435358
53	1999	0.102052842	7005	0.712697173
54	2000	0.105232537	9034	0.547169537
55	2001	0.108329697	10693	0.627480361
56	2002	0.107044449	9011	0.585844457
57	2003	0.105846562	12911	0.35938413
58	2004	0.109676418	15041	0.408835536
59	2005	0.110235118	15895	0.475686392
60	2006	0.107756259	13850	0.450186347
61	2007	0.105636132	9626	0.615404342
62	2008	0.101395754	8104	

Appendix G. Variable Cross Reference Table

With the exception of the Pipeline Tariff Submodule (PTS) all of the equations in this model documentation report are the same as those used in the model FORTRAN code. Table G-1 presents cross references between model equation variables defined in this document and in the FORTRAN code for the PTS.

Table G-1. Cross Reference of PTM Variables Between Documentation and Code

Documentation	Code Variable	Equation #
$R_{i,f}$	Not represented	157
$R_{i,v}$	Not represented	158
ALL_f	AFX_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	157
ALL_v	AVA_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	158
R_i	PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	157, 158
FC_a	Not represented	159
VC_a	Not represented	160
$R_{i,f,r}$	RFC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	161
$R_{i,f,u}$	UFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	162
$R_{i,v,r}$	RVC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	163
$R_{i,v,u}$	UVC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	164
$ALL_{f,r}$	AFR_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	161
$ALL_{f,u}$	AFU_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	162
$ALL_{v,r}$	AVR_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	163
$ALL_{v,u}$	AVU_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	164

Documentation	Code Variable	Equation #
ξ_i	AFX_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	222, 223, 225-228
$Item_{i,a,t}$	PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	222, 223, 225-228
$FC_{a,t}$	Not represented	222
$VC_{a,t}$	Not represented	223
$TCOS_{a,t}$	Not represented	224, 229
$RFC_{a,t}$	RFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	225
$UFC_{a,t}$	UFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	225
$RVC_{a,t}$	RVC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	227
$UVC_{a,t}$	UVC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	228
λ_i	AFR_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	225, 226
μ_i	AVR_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	227, 228
a - arc, t - year, i - cost-of-service component index		

Appendix H. Coal-to-Gas Submodule

A Coal-to-Gas (CTG) algorithm has been incorporated into the NGTDM to project potential new CTG plants at the census division level and the associated pipeline quality gas production. The Coal-to-Gas process with no carbon sequestration is adopted as the generic facility for the CTG. The CTG_INVEST subroutine calculates the annualized capital costs, operating costs, and other variable costs for a generic coal-to-gas plant producing 100 MMcf/day (Appendix E, CTG_PUCAP) of pipeline quality synthetic gas from coal. The capital costs are converted into a per unit basis by dividing by the plant's assumed output of gas. Capital and operating costs are assumed to decline over the forecast due to technological improvements. To determine whether it is profitable to build a CTG plant, the per unit capital and operating costs plus the coal costs are compared to the average market price of natural gas and electricity. If a CTG plant is profitable, the actual number of plants to be built is set using the Mansfield-Blackman market penetration algorithm. Any new generic plant is assumed to be built in the regions with the greatest level of profitability and to produce pipeline quality natural gas and cogenerated electricity (cogen) for sale to the grid.

Electricity generated by a CTG facility is partially consumed in the facility, while the remainder is assumed to be sold to the grid at wholesale market prices (EWSPRCN, 87$/MWh, from the EMM). Cogeneration for each use is set for a generic facility using assumed ratios of electricity produced to coal consumed (Appendix E, own—CTG_BASECGS, grid—CTG_BASCGG). The revenue from cogen sales is treated as a credit (CGNCRED) by the model to offset the costs (feedstock, fixed, and operation costs) of producing CTG syngas. The annualized transmission cost (CGNTRNS) for cogen sent to the grid is accounted for in the operating cost of the CTG facility.

The primary inputs to the CTG model include a mine-mouth coal price (PCLGAS, 87$/MMBtu, from the Coal Market Module (CMM)) and a regional wholesale equivalent natural gas price (NODE_ENDPR, 87$/Mcf). A carbon tax (JCLIN, 87$/MMBtu from the Integration Module) is added to the coal price as well as a penalty for SO2 and HG. If the CTG plant is deemed to be economic, the final quantity of coal demanded (QCLGAS, Quad Btu/yr) is sent back to the CMM for feedback. The final outputs from the model are coal consumed, gas produced, electricity consumed, and electricity sold to the grid.

Investment decisions for building new CTG facilities are based on the total investment cost of a CTG plant (CTG_INVCST). Actual cash flows associated with the operation of the individual plants are considered, as well as cash flows associated with capital for the construction of new plants. Terms for capital-related financial charges (CAPREC) and fixed operating costs (FXOC) are included.

$$\text{CTG_INVCST} = \text{CAPREC} + \text{FXOC} \tag{306}$$

Once a build decision is made, a Mansfield-Blackman algorithm for market penetration is used to determine the limit on the number of plants allowed to build in a given year. The

investment costs are further adjusted to account for learning and for resource competition. The methodologies used to calculate the capital-related financial charges and the fixed operating costs, the Mansfield-Blackman model, and investment costs adjustments are presented in detail below.

Capital-Related Financial Charges for Coal-to-Gas

A discounted cash flow calculation is used to determine the annual capital charge for a CTG plant investment. The annual capital recovery charge assumes a discount rate equal to the cost of capital, which includes the cost of equity (CTGCOE) and interest payments on any loans or other debt instruments used as part of capital project financing (CTGCOD) with an assumed interest rate of the Industrial BAA bond rate (MC_RMCORPBAA, from MACRO) plus an additional risk premium (Appendix E, BA_PREM). Together, this translates into the capital recovery factor (CTG_RECRAT) which is calculated on an after-tax basis.

Some of the steps associated with the capital-related financial charge estimates are conducted exogenous to NEMS (Step 0 below), either by the analyst in preparing the input data or during input data preprocessing. The individual steps in the plant capital-related cost estimation algorithm are:

0) Estimation of the inside battery limit field cost (ISBL)
1) Year-dollar and location adjustments for ISBL Field Costs
2) Estimation of outside battery limit field cost (OSBL) and Total Field Cost
3) Estimation of Total Project Cost
4) Calculate Annual Capital Recovery
5) Convert capital related financial costs to a "per-unit" basis

Step 0 involves several adjustments which must be made prior to input into the NGTDM; steps 1-4 are performed within the NGTDM.

Step 0 - Estimation of ISBL Field Cost
The inside battery limits (CTG_ISBL) field costs include direct costs such as major equipment, bulk materials, direct labor costs for installation, construction subcontracts, and indirect costs such as distributables. The ISBL investment and labor costs were provided for plants sited at a generic U.S. Gulf Coast (PADD III) location, and are in 2004 dollars.

Step 1 - Year-Dollar and Location Adjustments to ISBL Field Costs
Before utilizing the ISBL investment cost information, the raw data must be converted according to the following steps:

a) Adjust the ISBL field and labor costs from 2004 dollars, first to the year-dollar reported by NEMS, using the Nelson-Farrar refining industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 year dollars used internally by the NEMS.

b) Convert the ISBL field costs in 1987 dollars from a PADD III basis (Appendix E, XBM_ISBL) to costs in the NGTDM demand regions using location multipliers (Appendix E, CTG_INVLOC). The location multipliers represent differences in material costs between the various regions.

$$CTG_ISBL = CTG_INVLOC * BM_ISBL / 1000 \quad (307)$$

Step 2 - Estimation of OSBL and Total Field Cost
The outside battery-limit (OSBL) costs for CTG are included in the inside battery-limit costs. The total field cost (CTG_TFCST) is the sum of ISBL and OSBL

$$CTG_TFCST = (1 - CTG_OSBLFAC) * CTG_ISBL \quad (308)$$

The OSBL field cost is estimated as a fraction (Appendix E, CTG_OSBLFAC) of the ISBL costs.

Step 3 - Estimation of Total Project Cost
The total project investment (CTG_TPI) is the sum of the total field cost (Eq. 3) and other one-time costs (CTG_OTC).

$$CTG_TPI = CTG_TFCST + CTG_OTC \quad (309)$$

Other one-time costs include the contractor's cost (such as home office costs), the contractor's fee and a contractor's contingency, the owner's cost (such as pre-startup and startup costs), and the owner's contingency and working capital. The other one-time costs are estimated as a function of total field costs using cost factors (OTCFAC):

$$CTG_OTC = OTCFAC * CTG_TFCST \quad (310)$$

where,

$$OTCFAC = CTG_PCTENV + CTG_PCTCNTG + CTG_PCTLND + CTG_PCTSPECL + CTG_PCTWC \quad (311)$$

and,

CTG_PCTENV = Home, office, contractor fee
CTG_CNTG = Contractor & owner contingency
CTG_PCTLND = Land
CTG_PCTSPECL = Prepaid royalties, license, start-up costs
CTG_PCTWC = Working capital

The total project investment given above represents the total project cost for 'overnight construction.' The total project investment at project completion and startup will be discussed below.

Closely related to the total project investment are the fixed capital investment (CTG_FCI) and total depreciable investment (CTG_TDI). The fixed capital investment is equal to the total project investment less working capital. It is used to estimate capital-related fixed operating costs.

$$WRKCAP = CTG_PCTWC * CTG_TFCST \quad (312)$$

Thus,

$$CTG_FCI = CTG_TPI - WKRCAP \quad (313)$$

For the CTG plant, the total depreciable investment (CTG_TDI) is assumed to be equal to the total project investment.

Step 4 - Annual Capital Recovery

The annual capital recovery (ACAPRCV) is the difference between the total project investment (TPI) and the recoverable investment (RCI), all in terms of present value (e.g., at startup). The TPI estimated previously is for overnight construction (ONC). In reality, the TPI is spread out through the construction period. Land costs (LC) will occur as a lump-sum payment at the beginning of the project, construction expenses (TPI – WC – LC = FCI - LC) will be distributed during construction, and working capital (WC) expenses will occur as a lump-sum payment at startup. Thus, the TPI at startup (present value) is determined by discounting the construction expenses (assumed as discrete annual disbursements) and adding working capital (WC):

$$TPI_START = FVI_CONSTR * LAND + FV_CONSTR * (CTG_FCI - LAND) + WRKCAP \quad (314)$$

where,

FVI_CONSTR = Future-value compounding factor for an instantaneous payment made n years before the startup year

FV_CONSTR = Future-value compounding factor for discrete uniform payments made at the beginning of each year starting n years before the startup year.

The future-value factors are a function of the number of compounding periods (n), and the interest rate (r) assumed for compounding. In this case, (n) equals the construction time in years before startup, and the compounding rate used is the cost of capital (CTG_RECRAT).

The recoverable investment (RCI_START) includes the value of the land and the working capital (assumed not to depreciate over the life of the project), as well as the salvage value (PRJSDECOM) of the used equipment:

$$RCI_START = PV_PRJ * (LAND + WRKCAP + PRJSDECOM) \quad (315)$$

The present value of RCI is subtracted from the TPI at startup to determine the present value of the project investment (PVI):

$$PVI_START = TPI_START - RCI_START \quad (316)$$

Thus, the annual capital recovery (ACAPRCV) is given by:

$$ACAPRCV = LC_LIFE * PVI_START \quad (317)$$

where,

LC_LIFE = uniform- value leveling factor for a periodic payment (annuity) made at the end of each year for (n) years in the future

The depreciation tax credit (DTC) is based on the depreciation schedule for the investment and the total depreciable investment (TDI). The simplest method used for depreciation calculations is the straight-line method, where the total depreciable investment is depreciated by a uniform annual amount over the tax life of the investment. Generic equations representing the present value and the levelized value of the annual depreciation charge are:

$$ADEPREC = CTG_TDI / CTG_PRJLIFE \quad (318)$$
$$ADEPTAXC = ADEPREC * FEDST_TAX \quad (319)$$
$$ACAPCHRGAT = ACAPRCV - ADEPTAXC \quad (320)$$
$$DCAPCHRGAT = ACAPCHRGAT / 365 \quad (321)$$

where,

ADEPREC = annual levelized depreciation
ADEPTAXC = levelized depreciation tax credit, after federal and state taxes
ACAPCHRGAT = annual capital charge, after tax credit
DCAPCHRGAT = daily capital charge, after tax credit

Step 5 - Convert Capital Costs to a 'per-day', 'per-capacity' Basis
The annualized capital-related financial charge is converted to a daily charge, and then converted to a "per-capacity" basis by dividing the result by the operating capacity of the unit being evaluated. The result is a fixed operation cost on a per-mcf basis (CAPREC).

CTG Plant Fixed Operating Costs
Fixed operating costs (FXOC), a component of total product cost, are costs incurred at the plant that do not vary with plant throughput, and any other costs which cannot be controlled at the plant level. These include such items as wages, salaries and benefits; the cost of maintenance, supplies and repairs; laboratory charges; insurance, property taxes and rent; and other overhead costs. These components can be factored from either the operating labor requirement or the capital cost.

Like capital cost estimations, operating cost estimations, involve a number of distinct steps. Some of the steps associated with the FXOC estimate are conducted exogenous to NEMS (Step 0 below), either by the analyst in preparing the input data or during input data

preprocessing. The individual steps in the plant fixed operating cost estimation algorithm are:

0) Estimation of the annual cost of direct operating labor
1) Year-dollar and location adjustment for operating labor costs (OLC)
2) Estimation of total labor-related operating costs (LRC)
3) Estimation of capital-related operating costs (CRC)
4) Convert fixed operating costs to a "per-unit" basis

Step 0 involves several adjustments which must be made prior to input into the NGTDM; steps 1-4 are performed within the NGTDM.

Step 0 – Estimation of Direct Labor Costs
Direct labor costs are reported based on a given processing unit size. Operation and labor costs were provided for plants sited at a generic U.S. Gulf Coast (PADD III) location, and are in 2004 dollars.

Step 1 – Year-Dollar and Location Adjustment for Operating Labor Costs
Before the labor cost data can be utilized, it must be converted via the following steps:

a) Adjust the labor costs from 2004 dollars, first to the year-dollar reported by NEMS using the Nelson-Farrar refining-industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 dollars used internally by the NEMS (Appendix E, XBM_LABOR).

b) Convert the 1987 operating labor costs from a PADD III (Gulf Coast) basis into regional (other U.S. PADDs) costs using regional location factors. The location multiplier (Appendix E, LABORLOC) represents differences in labor costs between the various locations and includes adjustments for construction labor productivity.

$$CTG_LABOR = LABORLOC * BM_LABOR \quad (322)$$

Location multipliers are translated to the NGTDM demand regions.

Step 2 - Estimation of Labor-Related Fixed Operating Costs
Fixed operating costs related to the cost of labor include the salaries and wages of supervisory and other staffing at the plant, charges for laboratory services, and payroll benefits and other plant overhead. These labor-related fixed operating costs (FXOC_LABOR) can be factored from the direct operating labor cost. This relationship is expressed by:

$$FXOC_STAFF = CTG_LABOR * CTG_STAFF_LCFAC \quad (323)$$

$$FXOC_OH = (CTG_LABOR + FXOC_STAFF) * CTG_OH_LCFAC \quad (324)$$

$$FXOC_LABOR = CTG_LABOR + FXOC_STAFF + FXOC_OH \quad (325)$$

where,

FXOC_STAFF = Supervisory and staff salary costs
FXOC_OH = Benefits and overhead

Step 3 - Estimation of Capital-Related Fixed Operating Costs
Capital–related fixed operating costs (FXOC_CAP) include insurance, local taxes, maintenance, supplies, non-labor related plant overhead, and environmental operating costs. These costs can be factored from the fixed capital investment (CTG_FCI). This relationship is expressed by:

$$FXOC_INS = CTG_FCI * INS_FAC \quad (326)$$
$$FXOC_TAX = CTG_FCI * TAX_FAC \quad (327)$$
$$FXOC_MAINT = CTG_FCI * MAINT_FAC \quad (328)$$
$$FXOC_OTH = CTG_FCI * OTH_FAC \quad (329)$$
$$FXOC_CAP = FXOC_INS + FXOC_TAX + FXOC_MAINT + FXOC_OTH \quad (330)$$

where,

INS_FAC = Yearly Insurance
TAX_FAC = Local Tax Rate
MAINT_FAC = Yearly Maintenance
OTH_FAC = Yearly Supplies, Overhead, Etc.

Step 4 - Convert Fixed Operating Costs to a "per-capacity" Basis
On a "per-capacity" basis, the FXOC is the sum of capital-related operating costs and labor-related operating costs, divided by the operating capacity of the unit being evaluated.

Mansfield-Blackman Model for Market Penetration
The Mansfield-Blackman model for market penetration has been incorporated to limit excessive growth of CTG (on a national level) once they become economically feasible.[99] The indices associated with this modeling algorithm are user inputs that define the characteristics of the CTG process. They include an innovation index of the industry (Appendix E, CTG_IINDX), the relative profitability of the investment within the industry (Appendix E, CTG_PINDX), the relative size of the investment (per plant) as a percentage of total company value (Appendix E, CTG_SINVST), and a maximum penetration level (total number of units, Appendix E, CTG_BLDX).[100]

[99] E. Mansfield, "Technical Change and the Rate of Imitation," *Econometrica*, Vol. 29, No. 4 (1961), pp. 741-765. A.W. Blackman, "The Market Dynamics of Technological Substitution," *Technological Forecasting and Social Change*, Vol. 6 (1974), pp. 41-63.

[100] These have been defined in a memorandum from Andy Kydes (EIA) to Han-Lin Lee (EIA), entitled "Development of a model for optimistic growth rates for the coal-to-liquids (CTG) technology in NEMS," dated March 23, 2002.

$$KFAC = -LOG((CTG_BLDX / NCTGBLT) - 1) \quad (331)$$

$$PHI = -0.3165 + (0.23221 * CTG_IINDX) + (0.533 * CTG_PINDX) - (0.027 * CTG_SINVST) \quad (332)$$

$$SHRBLD = 1/(1 + EXP(-KFAC - (YR * PHI))) \quad (333)$$

$$CTGBND = CTG_BLDX * SHRBLD \quad (334)$$

where,

CTG_BLDX = maximum number of plants allowed
NCTGBLT = number of plants already built
SHRBLD = the share of the maximum number of plants that can be built in a given year
CTGBND = the upper bound on the number of plants to build

Investment Cost Adjustments

To represent cost improvements over time (due to learning), a decline rate (CTG_DCLCAPCST) is applied to the original CTG capital costs after builds begin.

$$CTG_INVADJ = CTG_INVBAS * (1 - CTG_DCLCAPCST)^{(YR - CTG_BASYR)} \quad (335)$$

where,

CTG_INVBAS = the initial CTG investment cost
CTG_BASYR = the first year CTG plants are allowed to build
CTG_INVADJ = the adjusted CTG investment cost

However, once the capacity builds exceed 1.1 bcf/day, a supplemental algorithm is applied to increase costs in response to impending resource depletions (such as competition for water).[101]

$$CTG_CSTADD = 15 * TANH(0.4 * (MAX(0, (CTGPRODC / 1127308) - 1))) \quad (336)$$

where,

CTGPRODC = current CTG production
CTG_CSTADD = the additional cost

[101] The basic algorithm is defined in a memorandum from Andy Kydes (EIA) to William Brown (EIA), entitled "CTL run-- add to total CTLCST in ADJCTLCST sub," dated September 29, 2006.