Working Paper Series

A Comprehensive Economic Impact Analysis of Natural Gas Extraction in the Marcellus Shale

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Workforce Development Challenges in the Natural Gas Industry

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Summary

Thousands of short and long-term jobs will be created as natural gas drilling and hydrofracturing takes place in the Marcellus Shale, presenting both employment opportunities and workforce development challenges. These jobs – found primarily on crews needed during the drilling and completion process – are not for everyone and require a diverse skill set and a rigorous work ethic. In Pennsylvania, the industry has thus far relied on "out-of-town" workers to fill many of these hard-to-fill roles, but over time will replace a portion of these workers with local employees if they are available. A similar pattern is likely to be repeated in New York if shale gas drilling is approved.

The number of workers needed will depend greatly upon the pace and scale of drilling – which has proven highly unpredictable in other areas. In general, local residents will find relatively fewer opportunities for accessible and stable employment in the short term, although opportunities may grow over time.

Local workforce training programs can help to "filter in" local employees that are well-suited to the industry, provide them with a basic orientation to the skills required, and steer these workers towards gas industry occupations that are safe, well-paying, and will keep them in the region for the long term. A concerted effort to match local workers with high quality jobs will

require investment in workforce education and training programs in community colleges, high schools, and other local educational institutions. Extensive workforce training programs are underway in Pennsylvania, while some smaller initiatives are being investigated in New York State.

Keywords

Natural Gas Industry, Marcellus Shale, Gas Industry Workforce, Workforce Development, New York State, Pennsylvania

Author

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What is the issue?

Fitting local workers with opportunities in the natural gas industry can be challenging as gas industry workforces are diverse, ranging greatly in the education or training required, with little in the way of an established industry training curriculum. While occupations can include advanced positions in engineering and geosciences, the majority of workers work in skilled trades, equipment operation, and general labor. Equally important to workforce development is the wide variation in the location and duration of these occupations: many workers associated with developing the gas wells will only be needed in a particular area while the wells are being drilled, while others related to the long-term production of natural gas will stay at a particular locale for decades.

Development of the Marcellus Shale – and the workforce it requires – is significantly more industrial in nature, labor intensive, and technologically advanced than the shallow natural gas drilling traditionally carried out in New York State and Pennsylvania.

What Kind of Jobs?

Nearly all jobs in the natural gas industry earn among the highest wages of any industrial sector, with a mean hourly wage of $34 per hour, typically excellent benefits (USBLS 2010), and dramatically increasing wages among highly skilled positions, including skilled trades such as specialized welding or crane operation, and positions in advanced fields such as engineering and geosciences. Non-experienced roustabouts or construction helpers can start at wages close to $20 an hour, with many opportunities for overtime (Jacquet 2006).

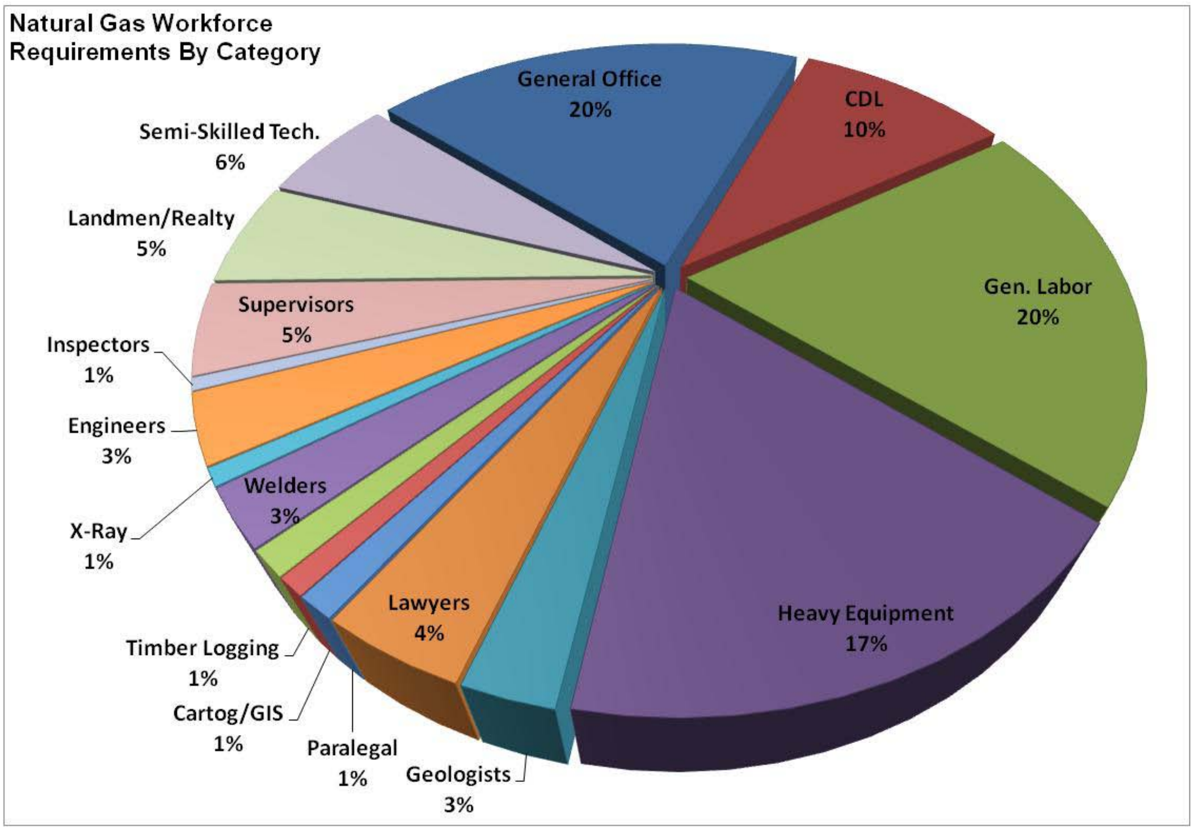

Figure 1: *This pie chart illustrates the composition of the over 400 occupations needed to drill a single well. It illustrates that most of the workforce is not in salaried occupations requiring advanced training or a college degree. (MSETC/Jacquet 2010)*

Drilling Phase Jobs vs. Production Phase Jobs

It is perhaps more informative to organize the onsite natural gas extraction workforce into two groups: **Drilling Phase Jobs** and **Production Phase Jobs**.

Clearing and constructing a natural gas well site, drilling and casing the well, performing the hydro-fracturing process, and constructing the associated pipeline infrastructure all considered part of the Drilling Phase, and a very labor-intensive process. After this work is performed, however, the number of workers needed to keep producing gas for the remainder of the life of the well -- the Production Phase -- is much smaller.

Drilling Phase Jobs. A worker-by-worker tally of the Marcellus Shale industry in Pennsylvania found that *the drilling phase accounted for over 98% of the natural gas industry workforce* engaged at the drilling site (MSETC 2009; 2010).

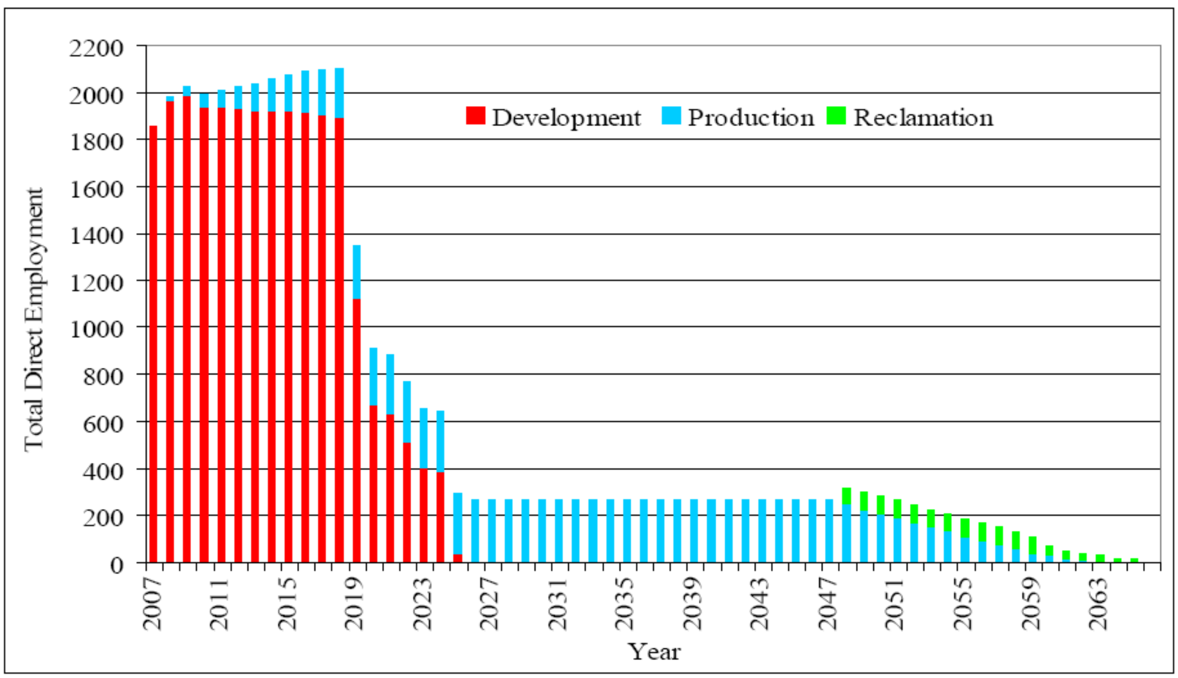

Figure 2: *This workforce projection from the Jonah natural gas field in Wyoming demonstrates that the workforce needed for the Drilling (or Development) Phase (red) is much larger than for the Production Phase (blue). The dynamic is very similar in the Marcellus Shale. In 2009, levels of drilling activity in*

the Jonah Field collapsed, due in large part to the economic recession, showing the volatile nature of the drilling phase and the difficulty in making accurate projections (ERG 2008/Jacquet).

The majority of these jobs include the "roughnecks" who work on drilling rigs, excavation crews, CDL (tractor-trailer) drivers, heavy equipment operators, hydro-fracturing equipment operators, and semi-skilled general laborers.

Because most of the job opportunities occur during the drilling phase of operations, and because drilling activity in a given locale can quickly escalate or decline, natural gas employment conforms to a pattern of "Boom" and "Bust" found in other types of mining and natural resource development activity -- where the population base may expand rapidly over a number of years before shifts in commodity prices, energy company business strategies, or natural resource policies cause extraction activity to collapse, leading new residents and workers to leave the community (Jacquet 2009; Haefele and Morton 2009).

Production Phase Jobs. While comprising less than 5% of the total workforce, jobs associated with the Production Phase of operations (i.e. the employees of the energy company operator required to manage gas production from existing wells) -- will remain local and predictable. A 30-year production phase is the typical estimate, although the reality varies by well, location, and market conditions. These production phase jobs will be required even if drilling ceases completely. *Occupations associated with the production phase tend to be less labor intensive, more location specific, less hazardous, and more specialized than development phase occupations, while still providing excellent wages and benefits*. During the production phase, a local company office typically monitors and maintains production on all existing wells in an area. Many operators' well locations are clustered to the degree that one office location will service all wells for that company in the region. Core jobs at these locations include well operators (or "well tenders"), instrumentation technicians, pipefitting and welding technicians, production engineers, and office staff. Most of these occupations require either experience or vocational education that makes employees well suited for on-the-job training.

The MSETC studies (detailed below) have found that approximately one worker is needed to monitor and maintain 6 wells under production. If thousands of wells are drilled over time, that eventually adds up to a significant number of long-term local jobs, although a much smaller number of jobs than are involved in the drilling phase, (MSETC 2010).

Office Jobs

A variety of administrative, accounting, public relations, and other business services are needed to support the companies performing drilling phase and production phase work, although in many cases these office-based occupations are found in regional or corporate headquarters, and are not hired in local communities where the drilling takes place. These "white-collar" office jobs in the gas industry tend to be more stable geographically than work that must be performed at a drilling location. Here, the Southwest region of Pennsylvania has an advantage over other Marcellus regions: many of the large natural gas companies have located their regional corporate offices in the greater Pittsburgh area, providing local Pittsburgh workers with opportunities to fill white-collar jobs in these offices. These regional offices constitute a "sub-hub", while the main center of long-term, highly paid employment in the industry remains concentrated at company headquarters located elsewhere, primarily in Texas.

The Predictions: How Many Jobs?

As with many other natural resource-based industries, predicting the future of natural gas drilling activity can be difficult. Commodity prices, technology changes, the discovery of new plays, and other factors can suddenly change the intensity, scope, and location of development. It can quickly become advantageous for an energy company to pull gas drilling operations out of one area, move them to another part of the state, country or the world, or put them on indefinite hold. It is likely that natural gas drilling in the Northeast United States will continue for many years; however, *where*, and *when*, and *how fast*, is much harder to predict (Berman 2010).

NYDEC's Development Scenario

In their Draft Supplemental Generic Environmental Impact Statement (DSGEIS), the New York State Department of Environmental Conservation (NYDEC) estimated that a maximum level of natural gas development is likely to be 500 wells per year (NYDEC 2009). NYDEC does not describe how they arrived at that figure, and in only three Pennsylvania counties just south of the New York border (Tioga, Bradford, and Susquehanna counties), energy companies drilled 909 wells in the year 2010 (PADEP 2011).

New York is home not only to the Marcellus Shale, which is likely to be most productive in the central Southern Tier region, but also to the Utica and other gas-bearing shales, which are thought to have a high potential for future development throughout most of Upstate New York.

The Considine Studies of Direct, Indirect, and Induced Employment

In the past two years, a series of studies on the economic impact of Marcellus Shale development have been commissioned by industry groups and performed by economist Tim Considine, in concert with other author-collaborators. Two of these studies (Considine et al 2009, and Considine, Watson, and Blumsack 2010) focus on Pennsylvania, but the third (Considine 2010) includes impacts on New York and West Virginia as well.

In their Pennsylvania analysis, Considine, Watson, and Blumsack (2010) found that 710 Marcellus Shale wells were drilled in Pennsylvania in 2009, and upon performing an input-output analysis using Impact Analysis for Planning (IMPLAN) data of the economic impact of this level of activity, they estimated that some 21,778 direct jobs would be created across all sectors, of which 2,878 would be created in the Mining Sector and 4,989 in the Construction Sector -- two industries most likely to comprise occupations related to the drilling of a natural gas well and associated activities.

In his New York analysis, Considine (2010) assumes that 314 wells will be drilled per year in New York State by 2015, which will generate 1,232 direct jobs in the Mining Sector and 2,154 direct jobs in the Construction Sector, two industrial classifications most likely to comprise the natural gas industry activity. He estimates an additional 4,810 jobs direct jobs will be created in all other sectors in New York, for a total of 8,196 direct jobs. And he estimates a further 7,532 indirect and induced jobs will result throughout all sectors.

The IMPLAN-based input-output model utilized by Considine assumes that most of the industrial, royalty, and wage spending that leads to job creation will occur in the area where the drilling takes place. This assumption may inflate the amount of job creation that is estimated in the model (Kay 2010[1]). In addition, the model assumes most of the jobs created will be "local" in nature. Therefore, it is unclear whether the economic model used in this study has accounted for the transient nature of much of the workforce, or the white-collar work performed at company headquarters located in other parts of the United States.

The Broome County Study

In 2009, the Broome County legislature commissioned an economic impact study from two Texas economists (Weinstein and Clower, 2010) that utilized an IMPLAN-based input-output analysis to predict the economic impact from shale gas development in Broome County, NY. The study assumed two different development scenarios: 2,000 wells are drilled in the county over a 10 year period (or approximately 200 wells per year), and 4,000 wells over ten years (or 400 wells per year). The study found that, under these two scenarios, total direct, indirect, and induced employment could be expected to reach 8,136 and 16,272 "worker person years" respectively -- the equivalent of 813 and 1,627 Full Time Equivalent jobs over the 10 year period, a number much smaller than in the Considine studies. This lower number reflects Weinstein and Clower's stated assumption that most of the employment creation would "leak" from Broome County (that is, occur outside the county), likely from a combination of out-of-town workers performing work locally and jobs that are created and performed elsewhere.

As the range in estimates indicate, it is impossible to accurately predict either the pace and scale of drilling or the number of local jobs that will be created. While the number of jobs created is significant - regardless of the methodology used - workforce development in the natural gas industry faces greater uncertainty than in many other industries.

[1] As part of this Policy Brief Series, David Kay, an economist at Cornell University, has provided a critique of the assumptions used in these economic models.

The MSETC Assessment of Direct Jobs

The Penn College of Technology's Marcellus Shale Education and Training Center (MSETC) has performed a number of regional workforce needs assessments focused on the Marcellus shale gas industry in Pennsylvania. Recognizing the complexity of the industry's drilling and production workforce, their method was to interview industry officials and contractors and observe operations to "hand-count" the occupations and number of direct workers needed to construct, drill, and complete a single well and move it into production. Their study found approximately 250 different occupations comprised of over 400 different individuals are required to drill a Marcellus Shale well. *However, the vast majority of these individuals and occupations are required for only a few hours or days for each well*. The number of Full Time Equivalent (FTE) workers (an FTE is equal to one worker working full time for a year) for these 410 individuals was about 13 FTE to complete a well (MSETC 2009; 2010).

Using the "maximum" amount of development predicted by the NYDEC -- 500 wells drilled in New York State per year -- this would result in the equivalent of approximately 6,500 full time jobs needed while drilling activity is occurring. It is important to note that these jobs are required only while wells are being drilled; once drilling activity stops, these jobs are no longer needed locally. Many times, drilling activity may pause, or move to another area of the play, or move to another part of the continent, forcing drilling crew workers to follow the work to a new location or find a new source of employment.

The MSETC study also found that for each well drilled the equivalent of 0.18 jobs are created to help maintain gas production for the life of the well. These jobs would be locally required for as long as the well is producing gas, a time frame that is often estimated at between 20 to 30 years, but which will vary from well to well. Since this much smaller portion of the workforce is required locally for the entire length of production, they do compound over time with each and every well drilled. For example, if 500 wells are drilled per year, 90 Production Phase jobs would be needed for a 20-30 year period; after 5 years of drilling, 450 jobs would be required for that amount of time; and so on. Over time, depending on the number of wells ultimately drilled in the region, jobs associated with the Production Phase can become significant source of "long-term" employment.

A Complex and Quickly Changing Workforce

Even if the total amount development activity is well understood, due to the varying work locations, residencies, work schedules, contractors, subcontractors, and development intensities, natural gas workforces are difficult to estimate.

A Complex Workforce

Development of the Marcellus Shale – and the workforce it requires – is significantly more industrial in nature, labor intensive, and technologically advanced than the shallow natural gas drilling traditionally carried out in New York State and Pennsylvania.

Consequently, the energy companies and contractors that perform drilling tasks are typically not local operations, but rather are national or international in scale and scope, and utilize personnel from around the country and around the world to perform these processes.

Further, the industry extensively depends on a wide array of subcontractors, each specializing in a few of the many complex tasks required, leaving the large energy firms that own the leases and the wells (typically called "operators") to perform the role of a general contractor during the drilling process. For example, the operator may contract out the services of an excavator, a drilling company, a hydro-fracturing company, and a well completion company, and in turn, each of these companies contracts out tasks such as logging, gravel, drilling supplies and services, environmental compliance, water hauling, cementing, etc.

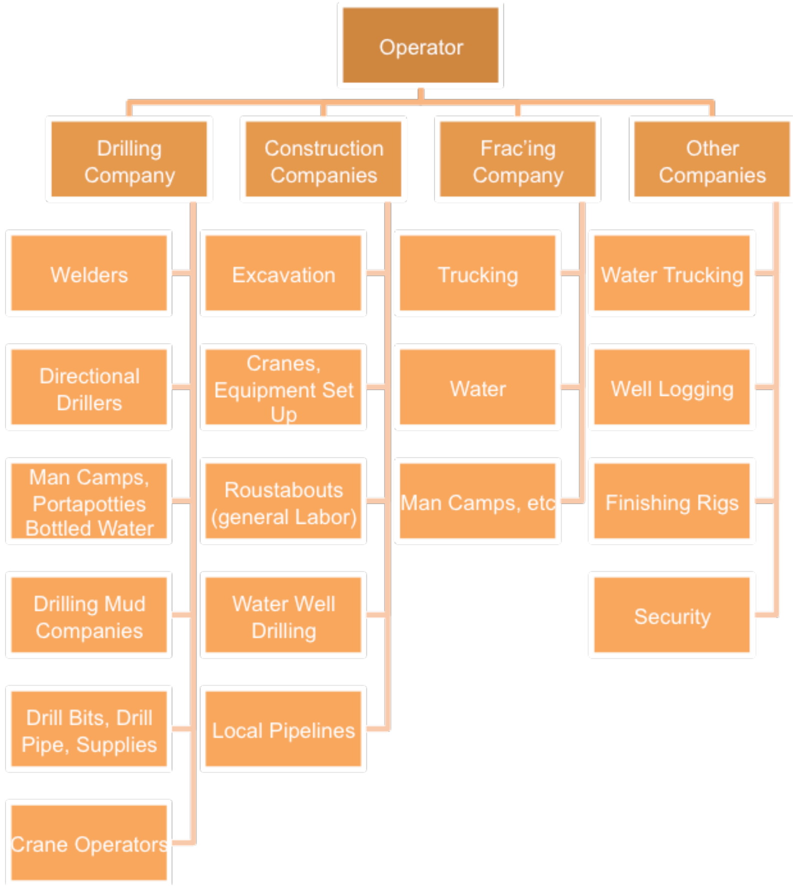

Figure 3: *An example of the main contractors and subcontractors of the natural gas operator.*

The complicated chain of contractors and subcontractors upon which the gas industry relies means that, unlike many other types of mining operations, relatively few people are actually employed "on the ground" by the large energy firms that own the natural gas well.

This system creates a challenge, not only in accounting for a workforce that is spread across a wide array of industrial classifications and geographical areas, but also because it leaves hiring practices and training programs largely uncoordinated among the myriad contractors and subcontractors. Many companies will provide on-the-job training to their workers – either in-house or via private training firms – but the focus of training remains largely company specific and uncoordinated among other firms.

A Quickly Changing Workforce: Locations, Schedules, and Worker Residency

Since many natural gas industry contractors and subcontractors are accustomed to working at multiple and changing locations throughout North America or the world, and because skilled workers are often needed very quickly, it is commonplace within the natural gas industry to utilize non-local workforces. Industry veterans will typically have worked in locations throughout the United States or the world. For New York or Pennsylvania workers who become well trained in the gas industry, this means that they may eventually be forced to work elsewhere, but will likely retain strong job security if they are willing to do so.

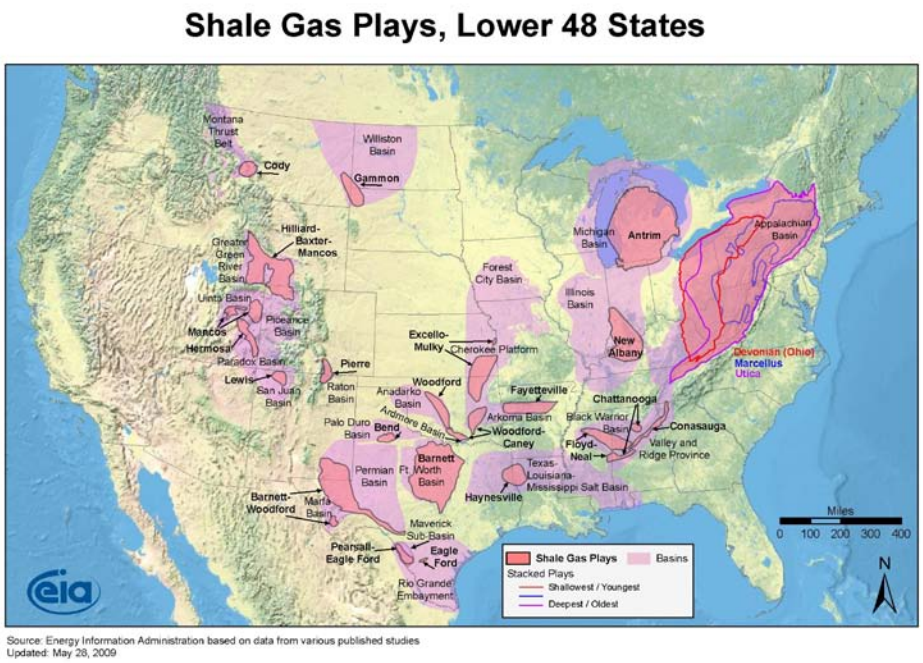

Figure 4: *Shale plays are emerging throughout the United States, and transferring natural gas workforces from play to play is commonplace and difficult to predict.*

Thus, the industry challenges the general definition of a "worksite", as employees supporting natural gas development often work in multiple locations within a region, and can develop hundreds of different wells and infrastructure projects. Furthermore, industry employees will sometimes work 12-hour shifts for weeks at a time, and then receive several continuous weeks of leave while an entirely new crew of workers takes their place.

The gas industry consistently battles one of the highest employee turnover problems of any industrial sector (Mallozzi 2010). Reliance on out-of-town workers can prevent local individuals from taking advantage of the high wages and benefits in gas drilling occupations, and the wages earned will leave the host community and be spent in the employee's place of permanent residence. Further, an influx of out-of-town workers can drive up costs to the community, as these workers require additional public and private community services.

However, in general, as development moves forward, the workforce will become somewhat more local to a region. Some employees will decide to fully relocate to the area. Some companies will construct regional offices. As employee turnover occurs, some employers will fill positions with locally-based workers if they are available. In Western states, employment statistics have shown natural gas industry employment increasing in local areas despite declining natural gas activity, reflecting jobs that have become more "local" to the area over time (Headwaters Economics, forthcoming 2011).

In the Marcellus Shale, the industry has thus far relied heavily on an "out-of-town" workforce that will tolerate these requirements and possesses prior experience from working in other natural gas development plays (WTAE 2010). However, in the Southwest region of Pennsylvania, where shale gas development activity has been occurring since 2004, the transition towards local workers has been underway for some time. Companies moving into that area of the Marcellus Shale initially brought an external workforce with them, but are in the process of replacing that workforce with local workers as opportunities arise. Local construction and service firms that serviced shallow gas development in the region have transformed their businesses to take advantage of work in the Marcellus Shale, although out-of-town workers still comprise a large but unknown portion of the total workforce (MSETC 2010; PSCE 2010).

Benefits of a Building a Local Workforce

Over time, however, in order to reduce their workforce costs, businesses within the industry will attempt to use local employees for many drilling phase positions and most of the production phase positions, if they are available. Local workforce training programs can serve to filter in local employees that are well suited to the industry, provide them with a basic orientation to the skills required, and steer these workers towards gas industry occupations that are safe, well-paying, and will keep them in the region for the long term.

One of the largest factors that influences the total economic impact projected by IMPLAN-based input-output studies is the extent to which wages that are earned locally *are spent locally*. Wages that are spent locally will flow through the local economy, providing economic stimulus to local businesses, in turn, creating more local jobs. This implies that capturing as many jobs as possible for long-term residents will create additional jobs, as they build homes and buy goods and services in the region.

However, the benefit from fostering a local workforce rather than an out-of-town workforce goes beyond the fact that more of their wages are spent locally. Gas development activity can produce strains on local communities as they struggle to provide housing, services, and cultural integration for the hundreds or thousands of workers that may arrive in a drilling area (Jacquet 2009). Providing workers that already have permanent housing, community ties, and are accustomed to local weather and culture can help to reduce this strain.

Local workforces benefit the industry as well. Reduced transportation costs are the most obvious, but as local workers are accustomed to the local area, they may lower rates of attrition, relocation costs, and commuting obstacles.

Training Opportunities

To foster local workforces, several post-secondary educational institutions across the United States have developed training programs or certifications to meet the demand of residents wishing to enter the gas industry. While there is not yet a recognized curriculum standard for most of the drilling and production phase jobs in the industry, the majority of these programs are one-to-two year programs offering an array of introductory classes in areas such as welding, electrical work, and instrumentation, with the content specifically tailored to gas industry applications in some cases. An important component to these programs is typically a "Gas

Industry 101" class that introduces students to the culture, terminology, schedules, and working conditions involved in the drilling industry, and serves to screen out potential employees who find these types of work unappealing.

Marcellus ShaleNet is a Pennsylvania-wide initiative to bring together Workforce Investment Boards (WIBs), their One Stop employment centers, training providers, and industry to build a Marcellus-wide, industry-recognized, uniform training and certification program by aggregating and augmenting existing curricula, and adopting best practices as identified" (WCCC 2010). The initiative has been developed by a consortium of community and technical colleges, anchored by the Penn College of Technology in Williamsport and the Westmoreland County Community College in southwestern PA, but it also includes Broome County Community College in New York and community colleges in West Virginia. The project was recently awarded a nearly $5 million grant from the U.S. Department of Labor (PCT 2010a).

A challenge faced by the traditional workforce development agencies in Pennsylvania and elsewhere has been differentiating the majority of agency clients looking for traditional kinds of employment from those well-fitted to work in the gas industry. Part of the ShaleNet grant involves implementing a "talent matching system" to identify well-suited individuals, and "when matches are not found, job seekers will be referred to appropriate training programs. […] The initial focus will be on recruiting and training low-income and dislocated workers, as well as military veterans, for in-demand positions such as derrick operators; rotary drill and service unit operators; roustabouts; welding and brazing operators; and truck drivers. " (PCT 2010a)

Penn College of Technology in Williamsport has created an industry fundamentals and orientation class called "FIT 4 Natural Gas", as well as natural gas-specific classes in welding, CDL, and Safety to complement other industrial classes that are available (PCT 2010b). Penn College plans to continue expansion of class offerings, including the use of onsite rig and wellhead equipment. In roughly 2 years, Penn College has graduated about 250 students from these classes, and has reported competitive placement thus far (Brundage, 2011). Over 1,100 students have also graduated from additional safety training, instrument and equipment certifications, and other shorter-term natural gas classes offered at Penn College.

Western Wyoming Community College located in Rock Springs, Wyoming is one example of a community college that provides a two-year certification in "Oil & Gas Technology" and "Natural Gas Compression" that is targeted toward long-term Production Phase employment in the oil and natural gas industry. The classes terminate in either an Associates Degree or one-year certification, with a curriculum that includes electrical, instrumentation, computer information systems, and industrial safety courses among others, and four classes designed specifically for oil and gas production with internships and apprenticeship placement built into the coursework. The program has operated since 2007, graduating an average of 17 students per year. The constructed well pad facilities on campus allow students to experience the job site under actual conditions (WWCC 2010).

Figure 5: *Students perform gas well operator functions on training equipment located on the Western Wyoming Community College Campus in Rock Springs, Wyoming.* (*http://www.wwcc.wy.edu*)

In New York, initial steps are underway to provide natural gas focused classes at Broome County Community College (BCCC) and Corning Community Colleges (CCC). BCCC was among the consortium of institutions to receive the ShaleNet grant from the Department of Labor, while Corning Community College is investigating possible credit and non-credit curriculum.

Conclusion

A small but significant portion of the jobs associated with natural gas drilling will be local, well paying, and long-term. Significant investments will be needed in local education institutions to provide technical and trade programs to local workers interested in these types of jobs. Examples of workforce training programs exist in other gas producing regions. They provide a basic orientation to the types of jobs available in natural gas drilling and production, the work conditions and equipment involved, and such rudimentary skills as safety practices, welding, and instrumentation. Such an orientation positions local workers as ready and "pre-fitted" for entry-level positions and on-the-job training provided by the gas industry.

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The Economic Consequences of Marcellus Shale Gas Extraction: Key Issues

A Research Project sponsored by the Cornell University Department of City & Regional Planning

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Table of Contents

Introduction

New York and Pennsylvania have a long history of natural gas extraction, including in the Marcellus Shale. Drilling is occurring currently in both states. Recent public concerns about shale gas drilling have revolved primarily around a specific technology -- high volume hydraulic fracturing (HVHF or "fracking"). Hydro-fracking uses millions of gallons of water infused with chemicals in a drilling process that fractures shale along bores drilled horizontally as well as vertically to extract gas from formations deep underground. The concerns with this technology have focused particularly on its potential effects on water supplies and quality. This is the central issue addressed in the Supplemental Generic Environmental Impact Statement (SGEIS) being developed by the New York State Department of Environmental Conservation. But the draft SGEIS, released in 2009, takes as a given that, while environmental considerations are important, exploitation of this new natural gas asset will produce significant economic benefits for New York's economy, reduce natural gas costs to state residents and industries, and provide for long-term economic development. Media coverage of issues surrounding shale gas development has tended to reinforce this assumption.

Natural resource extraction industries typically play only a small role in state economies; their employment impact is tiny compared to industries such as retail or health services On the other hand, these industries have major impacts on the regions where production takes place. Shale gas drilling brings an economic "boom" to the regions that experience it. As drilling companies move into a community, local expenditures rise on everything from auto parts to pizza and beer. New jobs are created in hotels and retail. Landowners receive royalty payments and have extra spending money in their pockets. This increased economic activity is eagerly anticipated in many parts of Pennsylvania and New York, especially in light of the "great recession". To fully assess the economic effects of shale gas drilling, however, policy makers and citizens need information on a wide range of questions: Who will get the jobs that are created? What about severance taxes? What are the costs of shale gas drilling to the public? How will the costs and benefits be distributed? How will other regional industries be affected? Where will the royalty money be spent? How long will the boom last, and what happens when it ends?

During the past year, a group of researchers centered at Cornell University undertook research to try to answer some of these questions, examining both the short-term (economic impact) and long-term (economic development) consequences of shale gas drilling and production. Our specific goal was to go beyond the narrow models that have been used to predict the economic impact of shale gas drilling, and to look at three issues:

1. How will the pace and scale of shale gas drilling affect the short-term and long-term economic consequences for counties in the Marcellus Shale gas play? What are the implications for job creation, in the short term and in the long term?
2. What costs do communities face in conjunction with shale gas drilling? What are the likely to be the cumulative effects of shale gas drilling and production, not only from the drilling process itself, but also from the industrial infrastructure required to transport and store the gas and to service the wells? How will these costs be affected by the pace and scale of drilling?
3. What evidence is there to tell us about the longer-term consequences of developing an economy dependent on natural resource extraction, and particularly natural gas extraction? What will happen after the boom-bust cycle of drilling ends? How will other key industries be affected?

Our research focused on Pennsylvania, where Marcellus HVHF drilling has already begun, and on New York, which is considering how to regulate HVHF. Many states in the U.S. have shale gas plays where HVHF is being used, however, and we can learn from their experiences about what to expect, both in the short term and in the longer term.

Because our goal was to answer complicated "how" and "why" questions, we used multiple methods including case studies, interviews, and descriptive statistics. Some of the data we gathered prompted us to ask, and enabled us to answer, questions about how the pace and scale of drilling could affect economic impacts. Overall, we wanted our research to inform the discussion of critical policy issues, and to provide citizens and policy makers with a framework for thinking about shale gas drilling and the questions it raises for long-term economic development in the Marcellus regions of Pennsylvania and New York.

This report presents executive summaries of the findings of research conducted in conjunction with the project from May 2010 to August 2011. (For a more in-depth picture on each topic, please download the complete working papers and policy briefs posted at http://www.greenchoices.cornell.edu/development/marcellus/policy.cfm.)

- Susan Christopherson and Ned Rightor lay out the factors that drive the boom-bust cycle characteristic of natural gas drilling, and their implications for the economic consequences of Marcellus shale gas extraction.
- David Kay emphasizes why we need to pay attention to the assumptions that underpin the models that have been used to project jobs and taxes in Pennsylvania and New York.
- Susan Riha and Brian Rahm tackle the water resource regulatory issues attending HVHF; their work makes the critical point that significant environmental dangers will

occur beyond the well site, and will have to be addressed both at the regional and at the state level.

- Andy Rumbach looks at the possible "crowding out" of tourism in drilling regions, and how to ameliorate the impact of drilling to retain a diversified economy.
- Jeffrey Jacquet explores what kind of public efforts will be needed to capture (short-term) drilling and (long-term) gas production jobs for local citizens in the parts of New York and Pennsylvania where natural gas jobs may dominate the local economy.
- Amanda Wilson and Lydia Morken take a look at one important area where regulation and public resources are needed to meet the challenges of shale gas extraction: public health monitoring and services.
- CJ Randall examines another important area of public costs from drilling, that of damage to local roads.
- And finally, Sara Lepori looks at how severance taxes in shale gas producing states have been used to pay for short-term public sector costs during the drilling boom, and protect long-term economic development prospects in drilling regions.

Susan Christopherson, Ph.D
Project Director

Acknowledgements

We are grateful for the financial support and personal guidance of Philip R.S. Johnson, Senior Program Officer for the Environment Program at the Heinz Endowments, and of Park Foundation Executive Director Jon M. Jensen and Program Associate Amy B. Panek, who together made this project possible. We are likewise grateful for the support of the Academic Venture Fund of the Cornell Atkinson Center for a Sustainable Future for our work on monitoring air and water quality in Marcellus Shale drilling regions, and for a grant from the Appalachian Regional Commission to the Southern Tier Central Regional Planning and Development Board that underwrote a companion study on potential impacts of shale gas extraction on the tourism economy of the Southern Tier, ably administered by STCRPDB Executive Director Marcia D. Weber.

More people than we can possibly name here contributed their knowledge and insights to our understanding of this complex and multi-faceted topic, and we would like to thank the many public officials, industry executives, researchers, technical experts, cooperative extension agents, community leaders, advocates, and interested citizens of New York and Pennsylvania who helped us in our efforts.

Those at Cornell University who contributed to both the substance and, crucially, the administration of this project include Katia Balassiano, Brett Chedzoy, Kristen Ford, Tom Frank, George Frantz, Al George, Danielle Hautenemi, Charlie Kruzansky, Susan Reed Lewis, Katie Lopez, Heidi Mouillesseaux-Kunzman, Zoe Nelson, Alexis Saba, Sarah Smith, Mort Sosna, Rich Stedman, Jeff Tester, Paula Willsie, and especially, Rod Howe and Robin Blakely-Armitage at CaRDI.

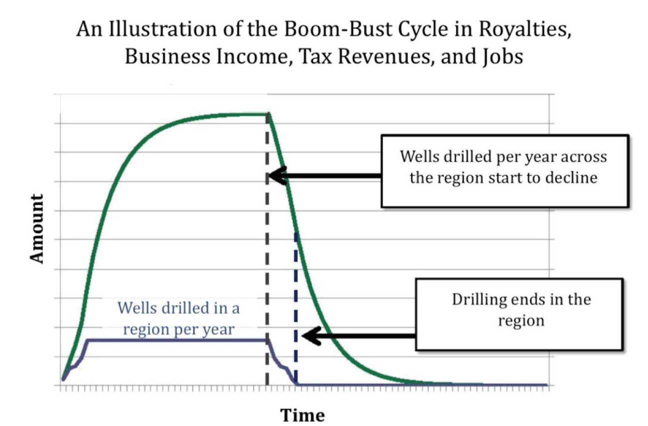
Then there's our intrepid research team. Not only the lead authors mentioned above, but City & Regional Planning Department Chair Kieran Donaghy, Isaac Argentineau, Tom Knipe, Vivien Li, Jack Lowe, Javier Perez Burgos, Sam Scoppettone, David West, and the members of the Spring 2011 CRP Workshop on the Marcellus Shale all contributed mightily to this project.

Finally, we would like to acknowledge in particular the members of the New York State Legislature who shared with us their thoughts and concerns: Aileen Gunther, Member of the Assembly, 98th District; Barbara Lifton, Member of the Assembly, 125th District; Donna Lupardo, Member of the Assembly, 126th District; and William Parment, former Member of the Assembly, 150th District. In New York, the necessary legislative action, authorizations, and appropriations to meet the challenges that we have identified now lies with them and their colleagues.

The Boom-Bust Cycle of Shale Gas Extraction Economies

Susan Christopherson and Ned Rightor

The extraction of non-renewable natural resources such as natural gas is characterized by a "boom-bust" cycle, in which a rapid increase in economic activity is followed by a rapid decrease. The rapid increase occurs when drilling crews and other gas-related businesses move into a region to extract the resource. During this period, the local population grows and jobs in construction, retail and services increase, though because the natural gas extraction industry is capital rather than labor intensive, drilling activity itself will produce relatively few jobs for locals. Costs to communities also rise significantly, for everything from road maintenance and public safety to schools. When drilling ceases because the commercially recoverable resource is depleted, there is an economic "bust" -- population and jobs depart the region, and fewer people are left to support the boomtown infrastructure.



Adapted from Tim Kelsey (2011), "Annual Royalties in a Community".

In the case of high volume hydraulic fracturing for Marcellus shale gas, the pace and scale of drilling will determine the duration of the boom period in the cycle. And because the public costs are greater with more rapid boom-bust cycles, communities and states anticipating this kind of economic pattern need to understand what will influence the pace and scale of drilling.

There are two ways to forecast the pace and scale of drilling in a shale gas play. The first is based on what is geologically and technologically possible: an analysis of total potential natural gas reserves and the capacity of existing or anticipated technologies. The other is based on business dynamics in the energy industry, and looks at what are the likely strategies of energy firms in response to their profit opportunities in particular shale plays and overall. An understanding of the choices made by operators and their subcontractors in a shale play requires an analysis of the costs and delivery rates of well operations, margins of commercial profitability, and corporate financial and competitive relationships.

For those living in the Marcellus Shale region, oil and gas industry assessments of the commercial viability of wells and how to best exploit the resource have important consequences. For example, in the Barnett and Haynesville shale plays, high initial production rates dropped off rapidly. What that means for shale gas dependent local economies is that the "bust" may come sooner than they expected, with adverse implications for tax revenues and jobs. Industry investment advisors are cautious about the long-term productivity of all U.S. natural gas plays.

But because the Marcellus Play is large and geologically complex, the play as a whole is likely to have natural gas drilling and production over an extended period of time. While individual counties and municipalities within the region experience short-term booms and busts, the region as a whole will be industrialized to support drilling activity, and the storage and transportation of natural gas, for years to come. Counties where drilling-related revenues were never realized or have ended may still be impacted by this regional industrialization: truck traffic, gas storage facilities, compressor plants, and pipelines. The cumulative effect of these seemingly contradictory impacts -- a series of localized short-term boom-bust cycles coupled with regional long-term industrialization of life and landscape -- needs to be taken into account when anticipating what shale gas extraction will do to communities, their revenues, and the regional labor market, as well as to the environment. Effective planning to moderate the speed at which extraction occurs, and a commitment to invest the short-term infusion of private and tax revenue in longer-term economic development, may mitigate the effects of the boom-bust cycle.

***Susan Christopherson** is a Professor in the Department of City and Regional Planning at Cornell University. She is an Economic Geographer, who has led a series of policy research projects to develop, analyze or evaluate strategies for economic development and job creation in New York State. **Ned Rightor** is President of New Economy Dynamics LLC, a research and consulting firm focused on workforce development and economic development projects throughout the northeast. Their complete report is available for download at http://greenchoices.cornell.edu/development/marcellus/policy.cfm.*

The Economic Impact of Marcellus Shale Gas Drilling: What Have We Learned? What are the Limitations?

David Kay

For several years, the prospects for energy development from gas deposits in tight shale formations have riveted the attention of natural gas industry boosters and detractors across the US. In southern and western shale-rich states, the shift towards shale gas production is definitively underway, if yet in its early stages. In New York in the middle of 2011, unconventional shale gas drilling remains on hold as debates over the pros and cons of a nascent 21st Century gas rush are fiercely engaged. In New York as well as in Pennsylvania, where shale gas drilling has only recently begun, the extensive Marcellus Shale formation is at the center of policy attention. Few natural resource issues have moved from obscurity to center stage in so dramatic a fashion and within such a short time frame.

Extractive natural resource development has frequently been described as transformative to regions that experience it. Many citizens believe that the future of New York's economy, environment, character, and quality of life are at stake because of the geographic breadth of the Marcellus natural gas play and the anticipated scale and pace of its development. Environmental issues, especially those involving water, are currently being intensively scrutinized. However, in this brief we focus our attention on the economy. Our primary goal is to review the existing research into the likely economic implications of shale gas development, and to raise questions about what policy makers need to know.

We highlight four key issues that have not been adequately addressed by existing economic impact models but which are critical to understanding the economic consequences of shale gas drilling.

- First: we examine existing input-output-based studies of the economic impacts of shale gas operations, focusing on those that have been referenced in New York State's still evolving environmental impact assessment documents. Because these studies involve projections based on models, we look carefully at several central assumptions that affect model results.
- Second: we discuss the most critical factor that will affect the regional and local economy – the uncertain pace, scale and geographic pattern of drilling operations, and the associated need to better understand oil and gas company decisions about where, when and how many wells to drill.
- Third: we highlight the need to better understand the economic behavior of landowners who receive a significant fraction of gas company local spending through leasing bonuses and royalties.
- Fourth: we review the long-term economic prospects for regions dependent on natural resource extraction industries. In particular, we consider the relevance of substantial research that points to the possibility of diminished long-term economic prospects for regions or communities that become overly dependent on natural resource extraction industries.

The amount of natural gas expected to be extracted and sold to consumers each year has the most influence on the results of all of the economic impact studies we review. In some studies, this quantity is a calculation based on drilling rates and sales actually observed in the recent past. In others, it is an assumption or projection into the future. However, even in more mature shale gas fields in southern and western states, only the early stages of a full development cycle have been observed. The Marcellus play is in the initial phase of exploration and production. Thus, assumptions or observations supporting the estimates of future drilling rates still involve significant uncertainty, are controversial, and deserve intense scrutiny. At this point, no single perspective can be said to have a lock on the 'right' estimate of the number of wells that will be drilled, the ultimate recovery rates of shale gas, or future gas prices.

The assumptions made about who has claims on the revenue streams generated by gas production are nearly as important as those about the rate of development of the play as a whole. Particularly critical for regional economic impact analyses are:

1. how drilling revenues will be split between people and businesses located inside the region versus outside the region; and
2. for money that does enter the region, the share that will go to landowners versus the share that will go to drilling related businesses.

Current estimates of these proportions are not strongly supported and will, in any event, evolve over time.

We conclude that existing evidence about the Marcellus shale gas operations is inadequate to make confident predictions about the numbers of jobs that will be created, business expansion, or revenue generation.

Gas development is already directing new money into the Marcellus region, and the prospects for substantial short-term economic gain for some local businesses and property owners are real. Many economic development opportunities will also arise.

On the other hand, mixed economic results are also occurring even in the short run. The rising tide is not likely to lift all boats: there will be losing communities, and individuals who are displaced or left behind. Moreover, the experience of many economies based on extractive industries warns us that short-term gains frequently fail to translate into lasting, community-wide economic development. Most alarmingly, a growing body of credible research evidence in recent decades shows that resource dependent communities can and often do end up worse off than they would have been without exploiting their extractive reserves. When the economic waters recede, the flotsam left behind can look more like the aftermath of a flood than of a rising tide.

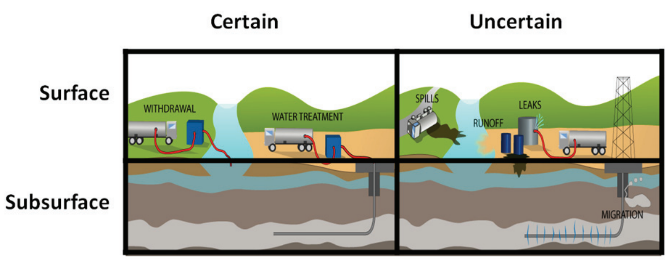
In the end, it seems clear that neither riches nor ruin are inevitable. The academic consensus is that the quality of policy and governance makes an important difference to the realization of an extractive industry's long-term economic development potential. The prospects for positive economic impacts in the short run should not blind policy makers to the potential for long term harm to overall economic development, especially when responsible, proactive policies may reduce and even reverse that risk.

David Kay *is a staff economist and Senior Extension Associate with the Community and Regional Development Institute in the Department of Development Sociology at Cornell University. The complete report is available for download at http://greenchoices.cornell.edu/development/marcellus/policy.cfm.*

A Framework for Assessing Water Resource Impacts from Shale Gas Drilling

Susan Riha & Brian G. Rahm

Recovering natural gas in the Marcellus Shale currently involves withdrawing large volumes of surface water, using large quantities of chemicals in close proximity to surface and ground water, disposing of waste water, and preventing gas and other formation fluids from entering potable groundwater during drilling and hydraulic fracturing. We present a framework for organizing and assessing these impacts on water resources that identifies (1) impacts that are certain, which can be planned for, as well as (2) impacts that are uncertain (accidents), which must be addressed through risk assessment, preventative practices, and reporting and monitoring structures. The Water Resources Institute framework can be used to help stakeholders better understand the wide range of events associated with shale gas drilling that will, or could potentially, impact water resources.



Distinguishing between certain and uncertain events is important from both a public policy and communications perspective:

- Certain events (those that are planned, such as water withdrawal and waste disposal) can be managed and regulated to minimize or avoid impairments to surface and groundwater, and also to control and monitor the scale and pace of development.
- Uncertain events (spills and leaks, contaminant migration) can be minimized by targeted regulation, encouragement of preventative management practices, establishment of timely and accurate reporting guidelines, and emergency response planning.

Distinguishing between surface and subsurface impacts is also useful. Surface impacts, which encompass a wide range of activities occurring at various locations, are more common than subsurface impacts, and are likely to represent a more significant threat to environmental water resources. Subsurface impacts associated with failures in cementing, casing and pressure management have received significant public attention and scrutiny, but are likely to pose relatively few and site-specific threats to water resource quality as compared to surface impacts.

Both surface and subsurface impacts warrant serious attention from all stakeholders. It is important for policy makers and regulators to understand their relative importance and differing causes so that proper measures can be taken to avoid or mitigate negative consequences. Making a distinction between surface and subsurface impacts is also necessary to determine whether or not current and proposed regulations adequately address various gas extraction related activities, and who should have the responsibility for regulating those activities. Identifying clear roles for local, state and federal agencies may help avoid lapses in critical oversight.

More specifically, we make the following suggestions with respect to public policy and shale gas regulation in New York State:

- A water withdrawal permitting system, with data collection and management functionality similar to that employed by the Susquehanna River Basin Commission, should be established state-wide. (NY State legislation on this issue is pending.)
- Use of private industrial treatment facilities (rather than municipal facilities) for highly concentrated and complex waste waters such as flowback and produced water.
- Stringent on-site containment practices to address water resource impacts associated with spills and leaks.
- A fast and transparent reporting system to ensure that unplanned events trigger effective responses from emergency and regulatory personnel.
- Testing of private drinking water wells pre and post gas drilling to establish any link between drinking water quality and drilling related impacts.
- General Stormwater SPDES permit requirements and/or other enforceable requirements for containment, monitoring, and compliance measures that take into account the unique phasing and layout of shale gas operations.

Unfortunately, gas extraction related events that have negative consequences for water resources will occur. New York has an opportunity to plan for mitigation of these impacts now. It also has an obligation to communicate to residents both the inherent risks of gas development and the allocation of responsibility for its regulation. Working together, industry and regulators can manage the range of possible negative impacts on water resources associated with shale gas drilling, and develop transparent monitoring and reporting systems that assure the public that shale gas drilling is occurring in a manner that protects our citizens.

For more information, please visit the New York State Water Resources Institute online at http://wri.eas.cornell.edu/

***Susan Riha** is Director of the New York State Water Resources Institute at Cornell University.*

***Brian G. Rahm** is a postdoctoral research associate, also with the NYS Water Resources Institute.*

*Illustration by **Laura Buerkle***

Natural Gas Drilling in the Marcellus Shale: Potential Impacts on the Tourism Economy of the Southern Tier

Andrew Rumbach

While much of the debate over gas drilling in the Marcellus Shale focuses on the potential environmental impacts, there is also concern that gas extraction will create a "boom-bust" economic development pattern seen in many resource rich regions and countries. Shale gas drilling in states like Wyoming, Texas, and Pennsylvania has had serious economic consequences for adjacent industries like agriculture and tourism because of the widespread industrial activity that accompanies drilling. This report examines the potential impacts of gas drilling on the tourism industry in the three-county region served by the New York Southern Tier Central Regional Planning and Development Board (STC).[1] Tourism is an important and diverse sector of the economy of the Southern Tier, and understanding the potential impacts of gas drilling on the tourism industry is important for business owners, elected officials, and planners concerned with economic development in the region. This paper addresses three major questions: 1) What is the value of the tourism sector to the economy of the STC region? 2) In what ways might gas drilling in the Marcellus Shale impact the tourism economy, now and into the future? 3) If gas drilling could potentially harm the tourism sector, what policies or strategies might help to mitigate those negative impacts? It is based on published reports, news articles, and studies related to gas drilling, empirical data from federal and state agencies, and interviews with public officials, gas drilling experts, business owners and operators, civic organizations, advocacy groups, and other local stakeholders.

The STC region has a diverse range of tourism assets, both urban and rural in character. The tourism "brand" of the Southern Tier is very much intertwined with agriculture; rolling hills, scenic farmlands, rural vistas, and viticulture all contribute to drawing tourists . Supporting and growing the tourism sector is a key component of economic development strategies for the counties in the STC region over the next several decades. In 2008, visitors spent more than $239 million in the STC region across a diverse range of sectors. The tourism and travel sector accounted for 3,335 direct jobs and nearly $66 million in labor income in the STC region that year. When indirect and induced employment is considered, the tourism sector was responsible for 4,691 jobs and $113.5 million in labor income.[2] In addition, the travel and tourism sector generated nearly $16 million in state taxes and $15 million in local taxes, for a total of almost $31 million in tax revenue -- a tax benefit of $1,181 per household. Though the tourism sector creates a significant number of jobs in the STC region, it is likely that the value of gas drilling, measured simply by jobs created and wages generated, will exceed the value of tourism in the short term. It is also likely that many tourism related businesses, including hotels, restaurants, and shopping venues, would benefit from the influx of gas workers. These observations come with two major caveats, however. First, tourism brings many non-monetary benefits to the STC region and its communities. Second, whereas many tourism related businesses are locally owned and operated and are thus part of a long-term economic development trajectory for the region, the employment "boom" in gas drilling will be relatively short-term and non-local.

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

The pace and scale of gas drilling will be a crucial determinant of the overall impact on the tourism economy in the Southern Tier. Nearly every negative impact of drilling listed above could be more or less disruptive depending on the pace and scale of drilling; fewer permits per year mean a lower volume of truck traffic on primary and secondary roads, fewer visual impacts and less chance of multiple rigs in view-sheds, an increased but not overwhelming demand on hotel rooms and short-term accommodations, fewer pressures placed on the local labor supply, and so on.

Municipal and County governments have many tools at their disposal to help mitigate the impacts of gas development. Municipalities can regulate many of the industrial developments associated with gas drilling through comprehensive planning and zoning or during the site planning process. These regulations might address the location, size, appearance, or operation of gas related infrastructure, buildings and sites, and should be developed and passed with the intention of mitigating the impacts of gas development on tourism and other adjacent industries. The full study makes additional recommendations that local and county governments take a proactive stance towards drilling and its attendant impacts by conducting truck traffic impact studies, making adjustments to the county room tax laws, and taking common-sense steps in site design and operations to reduce the visual impacts of drilling activities.

Prepared by ***Andrew Rumbach*** *for the Southern Tier Central Regional Planning and Development Board, with support from the Appalachian Regional Commission. Andrew Rumbach is an Assistant Professor in the Department of Urban and Regional Planning at the University of Hawaii. The complete report is available for download at http://www.stcplanning.org/index.asp?pageId=195.*

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[1] STC serves Chemung, Schuyler, and Steuben Counties in upstate New York.

[2] Employment numbers for the tourism and travel industries exclude wine production and vineyards. Wine and wine tourism is an emerging industry in the STC region, however, and employment in the industry is largely driven by tourism dollars. According to the New York State Department of Labor, 18 firms in the STC region were classified as "wineries" in 2010 and employed 275 people. An additional 8 firms were classified as "grape vineyards" and employed 63 people.

Workforce Development Challenges in the Natural Gas Industry

Jeffrey Jacquet

Summary

Thousands of (mostly) short-term and (some) long-term jobs will be created as natural gas extraction takes place in the Marcellus Shale, presenting both employment opportunities and workforce development challenges. These jobs – found primarily on crews needed during the drilling and completion process – are not for everyone; they require a diverse skill set and a rigorous work ethic. In Pennsylvania, the industry has thus far relied on "out-of-town" workers for many of these hard-to-fill roles, but over time will replace a portion of these workers with local employees -- if they are available. A similar pattern is likely to be repeated in New York.

Key Points

- Job creation is primarily dependent on the pace and scale of drilling, which has proven to be very difficult to predict.
- A study by Pennsylvania's Marcellus Shale Education and Training Center (MSETC) found that about 98% of jobs are concerned with developing the gas well, and are not needed after the well has been drilled, while 2% of the jobs are concerned with the long-term production of gas. If production lasts 20-30 years, and if many wells are drilled in a region, those production jobs can still amount to a sizeable workforce.
- The majority of jobs do not require advanced skills or training, but they do require a basic orientation to the industry and its technologies and terminology, as well as experience with the work conditions and schedules required.
- The industry is largely comprised of an array of independent contractors and subcontractors, and lacks a standardized training curriculum.

Development of the Marcellus Shale will be significantly more industrial in nature, technologically advanced, and labor intensive than the shallow natural gas drilling traditionally carried out in New York State and Pennsylvania.

Clearing and constructing a natural gas well site, drilling and casing the well, performing the hydro-fracturing process, and constructing the associated pipeline infrastructure are all considered part of the Drilling Phase. These jobs include the "roughnecks" who work on drilling rigs, excavation crews, CDL (tractor-trailer) drivers, heavy equipment operators, hydro-fracturing equipment operators, and semi-skilled general laborers.

After this work is performed, the number of workers needed to keep producing gas for the remainder of the life of the well -- the Production Phase -- is much smaller. MSETC found that approximately one worker is needed to monitor and maintain 6 wells under production. However, occupations associated with the production phase tend to be less labor intensive, more location specific, less hazardous and more specialized than drilling phase occupations, while still providing excellent wages and benefits. These include well operators (or "well tenders"), instrumentation technicians, pipefitting and welding technicians, production engineers, and office staff (although most office-based occupations are found in regional or corporate headquarters, and are not hired in the communities where drilling takes place).

While comprising less than 5% of the total workforce, jobs associated with the Production Phase will remain local and predictable, and these jobs will be required even if drilling ceases completely. Most of these occupations require either experience or vocational education that makes employees well suited for on-the-job training.

A Complex Workforce Training Opportunity

So, while a number of studies have projected impressive levels of job creation, the actual job picture will be much more complicated. In general, local residents will find relatively fewer opportunities for accessible and stable employment in the short term, although opportunities may grow over time. In Western states, employment statistics have shown natural gas industry employment increasing in local areas despite declining natural gas activity, reflecting jobs that have become more "local" to the area over time.

The complicated chain of contractors and subcontractors upon which the gas industry relies leaves hiring practices and training programs largely uncoordinated. Many companies will provide on-the-job training to their workers – either in- house or via private training firms – but the focus of training remains largely company specific. There is not yet a recognized curriculum standard for either the drilling or production phase jobs in the industry.

If they are realistic about the prospects for drilling phase vs. production phase jobs, local workforce training programs can help to "filter in" local employees that are well-suited to the industry, provide them with a basic orientation to the skills required, and steer these workers towards gas industry occupations that are safe, well-paying, and will keep them in the region for the long term. A concerted effort to match local workers with high quality jobs will first require significant investment in local educational institutions (community colleges, high schools, and other training programs) to provide workforce education, technical, and trade programs to local workers interested in these types of jobs. Examples of such workforce training programs exist in other gas producing regions, including those underway in Pennsylvania, while some smaller initiatives are being investigated in New York State.

The majority of programs are one to two years and offer an array of introductory classes in areas such as welding, electrical work and instrumentation, with the content specifically tailored to gas industry applications. An important component to these programs is typically a “Gas Industry 101” class that introduces students to the culture, terminology and equipment in the drilling industry, and the schedules and working conditions involved, which serves to screen out potential employees who find these unappealing. They provide a basic orientation to the types of jobs available in natural gas drilling and production, and such rudimentary skills as safety practices, welding, and instrumentation. Such an orientation positions local workers as “pre-fitted” for entry-level positions and on-the-job training provided by the gas industry.

Jeffrey Jacquet *is a natural resource sociologist, and has provided social and economic impact assessment of natural gas development since 2005. The complete report is available for download at http://greenchoices.cornell.edu/development/marcellus/policy.cfm.*

What Happens When Something Goes Wrong?

Dealing with public health issues that come with hydraulic fracturing

Amanda Wilson and Lydia Morken

What is the Issue?

As New York's Department of Environmental Conservation (DEC) works towards the final Supplementary Generic Environmental Impact Statement (SGEIS) for high volume hydraulic fracturing (HVHF) of the Marcellus Shale, counties are anticipating the potential impacts gas drilling will bring. County Health Departments (CHDs) "represent the front line in responding to concerns about public health impacts and nuisance issues" and will be the primary responder and investigator of water well complaints.[1] Will counties and their CHDs be able to fulfill this role once drilling begins? To answer that question, we surveyed CHDs in areas expected to experience drilling. We also spoke with current and former employees of the DEC, New York's Department of Health (DOH), the New York State Association of County Health Officials (NYSACHO), and the Conference of Environmental Health Directors (CEHD) to get their perspectives on the issue.

Abbreviations of Agencies Cited

DEC – NY Dept of Environmental Conservation
DMN – DEC's Division of Mineral Resources
DOH – NY Dept of Health
CHD – County Health Dept
EHD – Environmental Health Division
NYSACHO – NYS Association of County Health Officials
CEHD – Conference of Environmental Health Directors

What is the Role of County Health Departments?

CHDs perform a broad range of functions from lead poisoning prevention to restaurant inspections to private water well support. In the Preliminary Revised Draft SGEIS, DEC "proposes that county health departments retain responsibility for initial response to most water well complaints, referring them to the [DEC] when causes other than those related to drilling have been ruled out."[2] CHDs, the DEC, and the DOH are responsible for water well complaints (see Table 1), but exactly how the agencies will jointly investigate cases remains unclear.[3]

How CHDs are to respond to other HVHF-related public health complaints is also unclear. DMN indicates that: "Investigation of water well complaints … is the only role for CHD's [sic] discussed in the GEIS and SGEIS."[4] While CHDs may or may not have regulatory jurisdiction over other environmental health issues, they are often the "troops on the ground" who first respond to and report those issues, or who provide care for secondary public health impacts. Jurisdiction over any HVHF-related environmental health issue will depend on the level of government at which a relevant regulation is in place (e.g. if a municipal regulation pertains, a municipal agency responds; if a State regulation pertains, a State agency responds), the language in the final SGEIS, the nature of the problem, or the level of threat it poses to health and safety. But at this point, most CHDs have not made provisions for potential environmental issues beyond water well complaints, nor for possible secondary health impacts.

What Do County Health Departments Tell Us?

We interviewed County–level officials that typically handle water well issues in seven Southern Tier counties: Broome, Chemung, Chenango, Sullivan, Tioga, Schuyler, and Tompkins.[5] Counties differ in how they handle these issues; depending on the county, water well issues are investigated by an Environmental Health Division (EHD), a Watershed Protection Agency, a Water Resources Specialist, or a Code Enforcement Officer. We asked the responsible agency how their CHD anticipates handling complaints; whether they have the capacity and expertise to manage drilling-related health complaints; and whether protocols exist for handling various other public health impacts.

Agency	Responsibility
CHDs	• Primary role in initial complaint response; confirm well contamination and determine cause • Secondary role in complaint follow-up
DEC's Division of Mineral Resources (DMN)	• Secondary role in initial complaint response • Primary role in complaint follow-up once CHD finds contamination to be HVHF-related
DOH	• Assist CHDs in investigations of complaints

Most officials said that they lack the staff capacity, and in some cases the expertise, to handle an influx of calls and investigations. Most CHDs have the sense that the issue is out of their hands and are in "wait-and-see" mode. Some said they would like to plan ahead but lack time or resources, and do not know what to expect in terms of complaint volume. Some are looking for answers from the additional socioeconomic sections of the SGEIS to be released.

No additional resources have been identified for CHDs, and it is unclear how they will be able to respond to new public and environmental health concerns. Members of the CEHD have been meeting quarterly with DOH staff to address potential demands. But any support for the counties from the DEC, DOH, or other state-level sources will not be delineated in the final SGEIS, and instead must be brought about through a Memorandum of Understanding (MOU), a grant program, or legislation.

What Could Help County Health Departments Respond More Effectively?

In a letter to the New York State Association of County Health Officers (NYSACHO), the CEHD states: "The impacted counties WILL see a substantial increase in workload, and simply CANNOT handle it without appropriate funding for staff, analytical support, etc."[6] A list of key requests and concerns from CHDs and the CEHD includes:

1. A Statewide MOU.
CEHD advocates "A statewide Memorandum of Understanding (MOU)… between NYSDEC, NYSDOH, and the local health departments" for investigating water well complaints.[7] This MOU would outline the role and activities of all agencies involved, and would replace a 1985 MOU between the DEC and three counties (Allegany, Cattaraugus, and Chautauqua).

2. Response Resources.
CEHD recommends that additional funding for oversight "should be derived from the gas companies via permit fees, with a mechanism to transfer funds from NYSDEC to NYSDOH and [local health departments]".[8] No mechanism currently exists to redistribute permit fees to DOH or CHDs; to do so will require legislation. Article 6 reimbursements from the State for environmental health programs classified as "optional" by NYSDOH were eliminated from the 2011-2012 budget.[9] As CEHD urges, "State Aid funding dedicated to addressing individual water issues needs to be continued and enhanced."[10]

3. Representation and Involvement.
CEHD also requests a role in the gas permitting process led by DMN. Additionally, involved counties urge the appointment of DOH, county, and CHD representatives to DEC's new Hydraulic Fracturing Advisory Panel, formed to develop "recommendations to avoid and mitigate impacts to local governments and communities."[11]

4. Notification.
DEC recommends that "the (drilling) operator, at its own expense, sample and test all residential water wells…" in the vicinity prior to, during, and up to a year after drilling and hydraulic fracturing for natural gas, and that the test results be supplied to the well owner.[12] CEHD recommends that CHDs also receive those results for environmental health monitoring.

Conclusion

County Health Departments (CHDs) are the front line in responding to public and environmental health issues, whether or not the SGEIS designates them as the primary response agency. The requests by CEHD outlined above represent the minimum level of resources and authority they will need to adequately protect public and environmental health when HVHF drilling begins in the state.

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[1] CEHD letter NYSACHO, April 2011, page 2

[2] 2011 Preliminary Revised Draft SGEIS, Page 8-4

[3] See Table 8.1 of 2011 Preliminary Revised Draft SGEIS and Table 15.1 of the 1992 GEIS

[4] Personal communication with DEC's DMN, August 1, 2011

[5] Because Steuben and Delaware Counties do not have an EHD and refer environmental health concerns to a New York Department of Health (DOH) District Office, they were not interviewed.

[6] CEHD letter to NYSACHO, April 2011, page 2 (emphasis in the original)

[7] CEHD letter to DEC, Dec 2009, page 5

[8] CEHD letter to NYSACHO, April 2011, pages 1-2

[9] New York State Association of Counties and the New York State County Executives Association, "Enacted 2011-12 New York State Budget County Impact Summary," May 19, 2011, http://www.nysac.org/legislative-action/documents/11_12State_Budget-UPDATEDSummary.pdf

[10] CEHD letter to NYSACHO, April 2011, page 2

[11] DEC, http://www.dec.ny.gov/press/75416.html

[12] 2011 Preliminary Revised Draft SGEIS, page 7-46

Hammer Down: A Municipal Guide to Protecting Local Roads in New York State

C.J. Randall

What is the Issue?

Dust, noise, and road damage from industry truck travel are major citizen complaints in regions where shale gas is extracted via high-volume, horizontal hydraulic fracturing ("hydrofracking"). A typical Marcellus Shale well requires 5.6 million gallons of water, delivered and removed by truck. The initial drilling phase accounts for half of the estimated 625 to 1148 truckloads of water, additives, and drilling or fracturing equipment required for each well site. Unlike state highways and county primary roads, local roads are generally not built to stringent guidelines, and will not handle that volume of trucks or the weight those trucks typically carry. Local road quality management is imperative, and also provides a way that municipalities can manage the pace and scale of drilling.

Road Impacts and Costs

Road access and maintenance are critical to shale gas exploration. At the same time, drilling communities are seriously affected by the attendant road damage. Local roads have neither the width nor depth to handle sustained pummeling by heavy trucks; sinkholes, 6" to 10" of rutting, and complete road failures are not uncommon. The impact of 1000 extra trucks per year on a county primary road uses up 0.13% of that road's lifespan, but the impact of those same trucks on a town road consumes 2% of that road's life.

For example, damage from drilling trucks in PennDOT District 3-0 (Bradford, Columbia, Lycoming, Northumberland, Snyder, Sullivan, Tioga, and Union Counties) has been sustained and severe, and the District has had to post weight limits on 1500 miles of road since the start of Marcellus drilling. Overall, more than 4000 roads have been posted in Pennsylvania. Yet bond security costs for overweight truck travel on a posted road there – the financial incentive for a company to repair road damage – are limited to a maximum of $6,000 per mile for unpaved roads and $12,500 per mile for paved roads. This is adequate to cover only 10- 20% of the damage; road reconstruction can easily exceed $100,000 per mile. Additional public costs for protecting roads -- pre-bonding surveys, road condition surveys, new data collection systems, and posting roads -- are also significant.

Best Practices

The following is a set of best practices drawn from the experience of other states and shale plays:

- **Conduct a comprehensive traffic impact study** with the assistance of a traffic engineering firm to clearly define road structural classes (estimated cost: $3,000-$6,500).
- **Document baseline road conditions** and calculate the value of remaining road life (estimated cost: $1,000-$5,000).
- **Sign a Road Use Agreement** (RUA) at the time of permitting, requiring that the operator (drilling company) offset the predicted loss of useful life for the roads they will use at current reconstruction prices (estimated cost: $1,000-$3,000 for drafting).
- **Develop and implement a haul route management system** to keep heavy trucks off the most vulnerable roads (estimated cost: $3,000-$9,000).
- **Enforce load zoning**, ranging from routine patrols to high-intensity, multi-agency enforcement sweeps.

A comprehensive traffic impact study

A thorough study weighs different criteria to classify a given road into one of six structural classes, enabling municipalities to judge when that road's condition threatens public safety or the passage of critical operators such as emergency vehicles. It determines the total number of wheel loads of various magnitudes and repetitions the road can bear, describes the road's visual condition, and identifies the materials used to construct the road and their useful lifespans.

Variations in temperature change the stability of a road, and heavy truck traffic during the spring freeze-and-thaw cycle can wreak havoc. Test in May and again in August/September to collect a full range of data if possible; if not, test between June and October.

Document baseline road conditions

Take a video and photographic inventory of current road conditions, logging speed and where footage begins and ends geographically. Gather measurements of road length, width, pavement thickness, and sight distance.

Road Use Agreements (RUAs)

Some RUAs are complex documents conceived from a traffic impact study; others are simple contracts established years ago. A comprehensive RUA includes trigger clauses that require developers to submit haul routes to a town before a permit is issued, effectively connecting the RUA to road use. In New York, any RUA between a municipality and an operator should be placed on file with the NYS Department of Conservation as recommended in the SGEIS.

Haul route management

Heavy road use by Marcellus drillers lies at the legal confluence of the New York State Municipal Home Rule Law,[1] the Vehicle and Traffic Law,[2] and the Environmental Conservation Law (ECL),[3] a circumstance with no clear precedent. The statutory language of ECL-23 authorizes local governments to establish reasonable road regulations. Load zoning is permitted provided that the route provides access to all state routes entering or leaving town.[4] To be legally defensible, load limits must be based on a structural evaluation rather than determined arbitrarily by weight. Municipalities may not pass ordinances that impose a tax or fee for the use of public roads[5], but comprehensive RUAs that link capacity of the road to permitting for high-impact, high-frequency truck traffic may be implemented with the expressed intent of public safety and preservation of the road.

Enforcement

Reports from Pennsylvania's Northern Tier suggest that natural gas operators are running trucks carrying loads over the legal limit of 80,000 pounds for a semi-trailer truck. Since January 2010, Pennsylvania State Police have conducted 5800 roadside inspections of industry trucks; 42 percent of those resulted in pulling either the driver or vehicle out of service. Enforcement efforts come at a price, however; Pennsylvania's Department of Environmental Protection has invested $550,000 from the state's Waste Transportation Safety Account into unannounced roadside inspection blitzes.

Conclusion

There are engineering, logistical, and legal obstacles to insuring good management of local roads in the face of abrupt, high-intensity truck travel. The burden for implementation and enforcement of RUAs will be substantial for many localities. It is unclear what assistance state agencies will provide, and the process is as yet decentralized.

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[1] Municipal Home Rule Law §10[2]

[2] N.Y. Veh. & Traf. Law Art. 41 § 1660-1664

[3] New York State Environment and Conservation Law §23- 0303(2)

[4] N.Y. Veh. & Traf. Law Art. 41 § 1660, paragraphs 10 and 17

[5] N.Y. Veh. & Traf. Law Art. 41 § 1604

Marcellus Shale: The Case for Severance Taxes

Sara Lepori

There are multiple social, environmental and economic costs associated with the boom/bust cycle of energy development. Research indicates that a well-structured tax policy can play a significant role in paying some of these costs and insuring long-term economic development in regions affected by natural resource extraction industries. This brief addresses two questions that are often asked about severance taxes: 1) Do state severance taxes inhibit industry investment? 2) How can severance tax revenue cover short and long term costs of drilling?

The Role of State Severance Taxes

A severance tax is a tax imposed on the value of nonrenewable natural resources that will be used outside the state from which they are extracted. Severance taxes are instated to cover costs associated with resource extraction and to compensate the state for the loss of a non-renewable resource. With the exception of New York and Pennsylvania, all significant producing states impose a severance tax on fossil fuel extraction. Reports released by the Independent Petroleum Association of America, the national association representing U.S. independent oil/natural gas producers, prepare the industry to be responsible for these taxes.

When towns "boom" as a result of energy extraction, there are increased job opportunities and a growing population. Along with this short-term growth come increased public costs: for planning & zoning and other administrative services, for intensified road traffic and reconstruction, and for increased demands on schools, social services and public safety. These costs are predominantly paid for by state, county, and municipal governments. When natural resource extraction ends, communities face different challenges from the "bust": a decreased population and tax base, for example. The public costs associated with extraction are usually covered through taxation of the extracted resource via a severance tax.

Do Severance Taxes Deter Industry Investment?

The question of whether severance taxes affect industry decisions regarding when and where to drill is controversial. Headwaters Economics (2008) shows that in the 1990s Montana and Wyoming made divergent tax policy decisions. Montana decreased its effective tax rate (the ratio of production value to tax revenue), while Wyoming increased its rate. A decade later, Wyoming's tax rate for the energy industry is approximately fifty percent higher than Montana's. Both states have experienced a surge in natural gas drilling, yet Wyoming's production value (the product of price times production volume) is 5 times as high as Montana's. It appears in comparing Wyoming with Montana that tax increases did not deter firms from investing.

Drilling is influenced first and foremost by reserves. The preponderance of evidence (Gerking, 2000, Kunce 2001) indicates that severance taxes have little effect on natural gas company decisions about where and when to drill. State severance taxes are deductible against federal corporate income tax liabilities, so their effect on the company's "bottom line is greatly reduced. Other factors such as gas price, labor costs, access to markets (e.g., oil and natural gas pipelines), technology, and regulations have the most significant effects on industry activities.

Some economic models indicate that severance taxes may affect the pace and scale of drilling. Considine's model (2009) showed a decrease of 30% in drilling activity in Pennsylvania, whereas an economic model completed by Center for Business and Economic Research of the University of Arkansas (2008) indicated a 13% decrease. These divergent conclusions suggest that while severance taxes do not curtail investment in drilling activity they may affect the pace and scale of drilling. Taxes can increase without risk of losing industry investment and a slower pace of drilling can benefit regions, enabling them to adjust to the impacts of the drilling economy over a longer period of time. Regardless of change in pace, drilling is ultimately driven by the reserves available.

Covering Public Costs

Studies of severance tax policy consistently make the following recommendations to insure that states cover the costs of drilling and insure long-term economic viability in drilling regions.

1. Create a tax that effectively pays for the short-term and long-term costs of drilling. States can impose a severance tax without risk of reducing production or industry jobs. If a state has a severance tax that is too low, shale gas extraction will require a significant amount of additional government services without commensurate fiscal benefits.

2. Distribute tax revenue predictably and fairly between state and local governments. There are many ways to allocate revenue that are aligned with the costs of drilling. Regardless of the exact distribution, the primary purpose of a severance tax is to cover costs born by the local and county governments.

3. Limit deductions and exemptions. Many states have relatively high tax rates but so many tax loopholes that the effective tax rate does not cover the cost of administering it, nor the short and long term costs of drilling.

For example, Colorado, the 6th largest state producer of natural gas, has a tax rate set on a sliding scale between 2-5%. The state subtracts property tax from the taxable value and exempts certain wells from taxation. As a result the realized severance tax is between 2.5-0.3% each year. Constructing a tax that is straightforward and simple makes compliance easier for gas producers and tax officials. Because the structure of the tax determines how volatile it will be, exemptions and loopholes should be minimized.

4. Establish a Permanent Fund. A Permanent Fund is the most effective way to promote long-term economic development. For example, every state in the intermountain west invests in a permanent find. The permanent fund serves to protect the state against future recessions, yearly revenue volatility, and to ensure ongoing fiscal benefits from the depletion of a non-renewable natural resource.

Resources

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How shale gas extraction affects drilling localities: Lessons for regional and city policy makers

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Abstract In countries around the world, the public debate over the prospect of high volume hydraulic fracturing for shale gas has revolved around its environmental impacts, while taking as a given that exploitation of this newly available natural gas asset will produce significant economic benefits for local and regional economies. In this paper the authors use multiple methods, including a case study of the Marcellus Shale gas 'play' in the USA, to examine how the economic costs and benefits of high volume hydraulic fracturing have been assessed. They argue that the economic impact models, which have been used to project potential benefits and job creation, provide only a fraction of the information needed to understand the consequences of drilling for the regions in which it occurs. The paper also examines some of the challenges local communities face in responding to the costs posed by shale gas extraction. The authors' analysis indicates that, while shale gas development may increase jobs and tax revenues in the predominantly rural regions where drilling occurs, it can also impose significant short- and long-term costs. To fully assess the economic effects of hydraulic fracturing, local and regional policy makers need to understand the boom-bust cycle that characterises natural gas development. This cycle has implications for local costs and benefits short term, and for the longer-term economic development prospects of localities in drilling regions.

Keywords: *Marcellus Shale, shale gas, high volume hydraulic fracturing, economic impact, economic development, local planning, local regulation*

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INTRODUCTION

High volume hydraulic fracturing for natural gas (HVHF, or as it is frequently called, 'hydro-fracking' or 'fracking') is being attempted in shale deposits around the world, including in the UK, Continental Europe and Canada. In the USA, the discovery of large shale gas deposits in many areas of the country has stimulated natural gas development, producing historically low prices for the commodity. At the national scale, the discovery and exploitation of natural gas assets has been welcomed, particularly in the wake of long-term economic stagnation.

At the local level, the calculation of costs and benefits is more complicated. Like all resource extraction industries, hydraulic fracturing is characterised by a boom-bust cycle. Jobs and spending rise dramatically in localities during the drilling or boom phase of shale development, but drillers leave the region when the commercially viable resource is fully extracted, producing an economic bust. In situations such as that occurring in contemporary USA, where a number of states are engaged in shale gas extraction, drilling rigs may move at short notice from one region to another, causing a series of economic disruptions as drilling starts up, shuts down and starts up again.[1] Regions hosting natural resource development industries have historically been characterised as afflicted by a 'resource curse' because, while the natural resource extraction boom brings jobs and population growth for a few years, it also increases public service costs and 'crowds out' other industries. Boom towns also frequently experience social problems brought about by the influx of a transient population that follows the oil and gas industry rigs from one place to another. After the boom ends, and the drilling crews and their service providers depart, the region may have a smaller population and a poorer economy than before the extraction industry moved in. If the boom-bust cycle is combined with environmental damage, the long-term costs to regions hosting the hydraulic fracturing gas extraction boom may be considerable.

Despite the potential economic and social problems associated with boomtown economies, it is environmental issues that have dominated public discussion of shale gas drilling in the USA. Environmental concerns revolve primarily around a particular technology HVHF — that uses millions of gallons of water along with chemical additives in a drilling process that fractures shale along bores drilled horizontally as well as vertically to extract more gas from formations deep underground. The questions about this technology have focused particularly on its effects on water supply and quality. Many of the environmental risks associated with fracking, however, are a result of the regional industrialisation connected with natural gas development. They occur on the surface rather than underground at the well site, including for example, air pollution from the thousands of trucks required to service the wells and from compressor plants along the pipelines that move the extracted gas to market. These risks are evaluated differently from one community to another and from one country to another. France has banned hydraulic fracturing because of worries about its effects on wineries and tourism; earthquakes connected with test drilling have stalled hydraulic fracturing in Lancashire in the north west of England; the Canadian province of Quebec has instituted a moratorium because of public fears about water contamination; and in the USA, the state of New York established a one-year moratorium on hydraulic fracturing in order to better assess its effects on the environment, including on local community character. AQ1

While there is an active international debate about the environmental consequences of hydraulic fracturing, it has been difficult for localities and regions to assess the predictions about how their economies will be affected by the drilling. Very little research has been conducted on the economic and social costs associated with hydraulic fracturing during the boom phase of development, or on what

Figure 1: Image from the report *World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States* prepared for the US Energy Information Administration (EIA), US Department of Energy (April 2011), available at: http://www.eia.gov/analysis/studies/worldshalegas

will happen when the drilling phase ends.

In an attempt to close this gap, the authors review the evidence concerning the short-term (economic impact) and long-term (economic development) consequences of shale gas drilling and production, and examine the methods that have been used to project economic benefits. They demonstrate why an understanding of the boom-bust cycle of natural resource extraction is critical to an accurate calculation of how hydraulic fracturing will affect the local and regional economies where it takes place. They also describe some of the significant costs to communities that are typically associated with natural resource extraction booms. Finally, some of the planning measures that can mitigate the costs associated with natural resource extraction for the affected regions and localities are examined.[2]

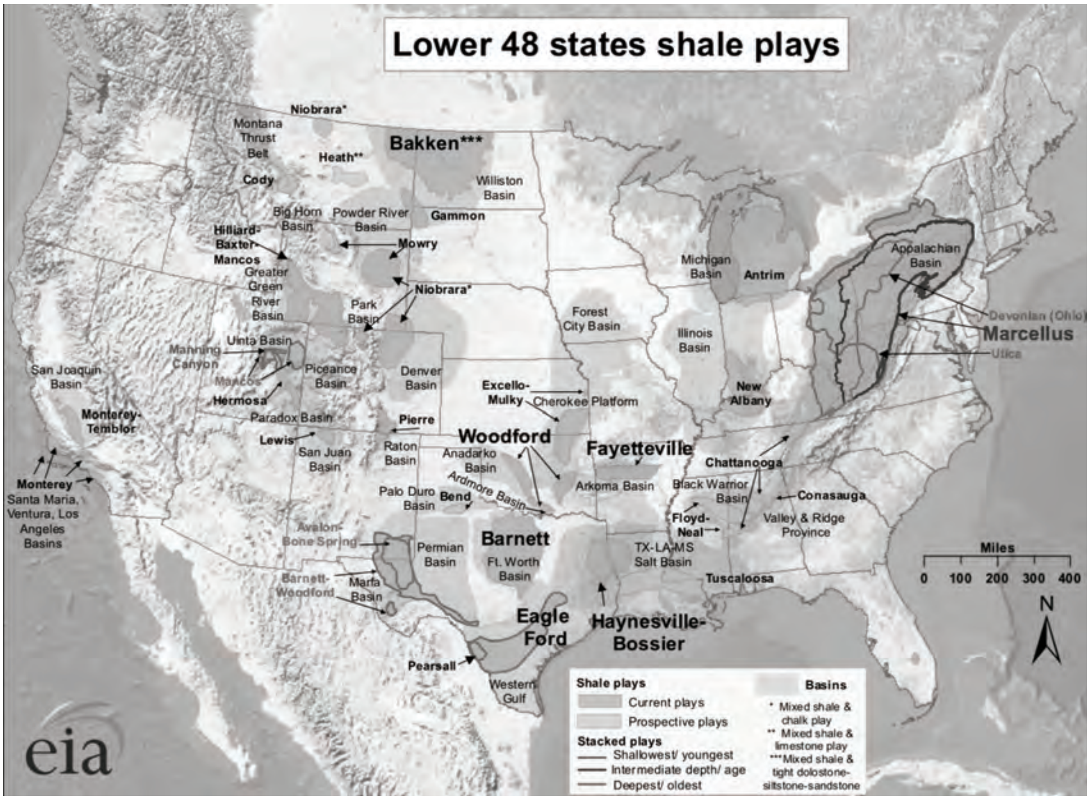
As an empirical anchor, particular attention is paid to a specific region at the centre of shale gas development in the USA — the Marcellus Shale gas play in the northern counties of Pennsylvania and southern counties of New York (Figure 2).

HOW HAVE THE ECONOMIC BENEFITS AND COSTS OF HYDRAULIC FRACTURING BEEN ASSESSED?

Despite concerns about the environmental damage that may result from fracking, US policy makers and the public generally assume that exploitation of this new natural gas asset will produce significant economic benefits for the regions where it occurs, reducing natural gas costs to residents and industries, and providing for long-term economic development. Media coverage of issues surrounding shale gas development has tended to reinforce this assumption.

The idea that dramatic, widespread and long-term economic benefits will accompany shale gas drilling is put forward in a series of input/output model based economic impact reports (EIRs) that have been supported by the oil and gas industry or its associated lobbying organisations.[3]

For policy makers and citizens, the utility of the information provided by these models depends on a clear



Source: Energy Information Administration based on data from publisherd studies. Updated: May 9, 2011.

Figure 2: Map image available from the US Energy Information Administration website at: http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm#field

understanding of the assumptions behind and limitations of input/output (IO) models. In presentations of model results, however, critical information needed to assess the model results is sometimes missing. A model developed by IHS Global Insight, for example, projects that the shale gas industry supported 600,000 jobs in the US economy in 2010 and will support 870,000 in 2015. The model predictions are based on the number of wells to be drilled in the USA.[4] But because no information is provided on the number of wells the industry predicts it will drill, it is impossible to assess or validate the results of the model.

In addition, while IO models project the number of jobs that could be created from a certain level of expenditures on each well, they cannot tell us how many actual jobs will be created, who will get those jobs, or what they will pay. The fact that IO models can only provide job estimates is often ignored, and those estimates are portrayed incorrectly as real job numbers. Ultimately, because of the simplifying assumptions necessary to construct IO models, they cannot be used to analyse wide-ranging structural changes in a regional economy, such as those that occur in conjunction with hydraulic fracturing. These kinds of changes might include increased competition for labour across industries, or decreased ability to retain or attract other industries because of the noise and pollution associated with HVHF.

Kay[5] provides a thorough analysis of the IO model approach to economic impact prediction, emphasising that models can produce very different results depending upon the assumptions on which they are built. The most important assumptions affecting the results from these models are those regarding the pace, scale and geographic distribution of drilling activity.

An example of the care that needs to be exercised in evaluating the results of IO models and their underlying assumptions is the Broome County, New York economic impact study, which was developed very early in the learning curve on Marcellus shale gas drilling. The study authors assumed that hydraulic fracturing would occur uniformly across the County.[6] Analyses of actual drilling patterns in Pennsylvania demonstrate that this scenario (and the assumptions about expenditures that follow from it) is not realistic. Drilling locations are influenced by infrastructure (pipeline and compressor station) access, by topographic and geologic data used to target ease of drilling and high value results, by political considerations including proximity to potentially sensitive locations such as hospitals and schools, and potentially, by zoning regulation.[7] These locations are unlikely to be spread evenly across the terrain of a county. Calculating the amount of drilling that will occur by assuming that wells will be drilled over every acre of the County produced an unrealistic estimate of the amount of expenditures likely to occur in the County. The authors qualify their assumption by presenting a second scenario that cuts the total number of wells to be drilled in the County in half, but this is no more than a guesstimate. The authors do not attempt to determine either the pace or scale of drilling that is likely to occur in the County (based on an analysis of the pattern of drilling in other shale gas plays, for example), or factors likely to affect industry investment in a natural gas market where, in 2011, prices are at historic lows. Rather, they assume full development of the County's natural gas well sites within a short time frame.

The projections of job creation and local revenues constructed in IO analyses also depend on assumptions about where expenditures associated with the drilling of each well will be made. Given the geographic organisation of the US oil and gas industry and the concentration of all inputs (manufacturing of equipment, drilling labour, engineering services, etc) in Texas and Oklahoma, it is expected that — while there are local industries that *could* provide inputs to the drillers — a high proportion of expenditures associated with Marcellus shale drilling will be made outside New York or Pennsylvania. Again, an IO model only estimates *potential* regional expenditures. It cannot show that the projected expenditures will actually occur in the drilling region or whether they will rebound to the benefit of the region. Although oil and gas companies indicate that the largest portion of their expenditures in Marcellus Shale regions will take the form of payments to landowners,[8] there is little information to show where landowner leasing bonuses or royalty payments will be spent. If land or mineral rights owners live outside of the drilling region, it is unlikely that they will spend their payments in the localities where drilling is occurring, although they will be subject to taxes in those localities.

Evidence from already developed shale plays indicates that shale gas drilling relies heavily on a workforce that resides in Texas and Oklahoma and moves with the rigs from one shale play to another. Local employment is concentrated in trucking, construction, and retail jobs — many of which are part-time, short-term, and low-wage. Input/output model projections are rarely compared with actual employment data after the industry begins to develop. Using Pennsylvania Department of Labor and Industry data, however, the Keystone Research Center in

Pennsylvania indicates that Marcellus core industries have created approximately 9,300 jobs in that state since the shale development boom began in 2007. These numbers are significantly lower than the 48,000 jobs projected in the industry-supported IO studies.[9]

Finally, the types of IO models typically used to measure the economic impact of HVHF are only snapshots of the regional economy during the entire drilling cycle; they are static rather than dynamic. Because they are constructed around projected expenditures for the drilling of each well, the models do not indicate when expenditures will be made, whether they will be volatile or predictable, and when they will end. They focus their attention on the boom period, when money and population are flowing into the region. In reality, the drilling boom phase of the boom-bust cycle that characterises resource extraction industries may be brief, lasting under ten years. Input/output models cannot forecast what to expect in terms of the time frame for drilling investment, or what will happen when drilling ends.

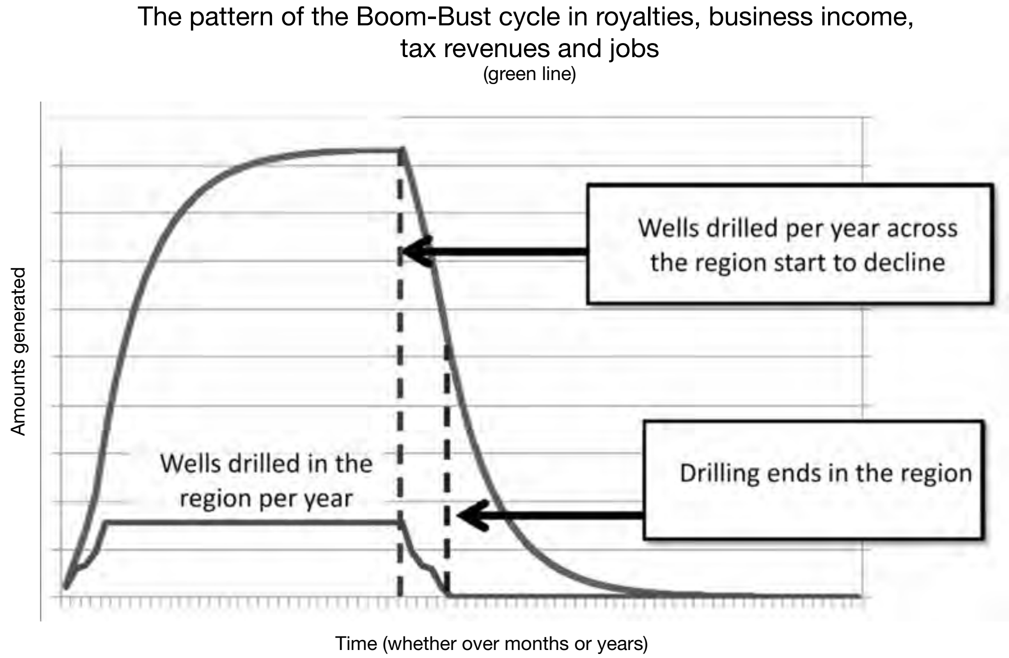
The limitations of the models that have been used to project the economic impact of shale gas drilling suggest that local policy makers need to read the results of EIRs carefully and with some skepticism. They need to look at the assumptions that underlie calculations of jobs and revenue to see if they realistically portray where, when and how drilling and the expenditures associated with it are likely to occur. While these models provide projections of job creation and tax revenues, they cannot substitute for an analysis of the actual costs and benefits of the production process. For newer shale development regions like the Marcellus Shale, some information 'grounded' in actual experience is available: from case studies of regions that have been through the unpredictable production cycle that characterises natural gas extraction.[10]

In the next section the authors examine why it is necessary to know more about the factors that influence the pace and scale of drilling in order to understand its impact on shale gas drilling regions, both in the short term — the drilling phase, and in the long-term — once drilling has declined as a major stimulus to the regional economy.

THE PACE AND SCALE OF DRILLING AND THE BOOM-BUST CYCLE

The extraction of non-renewable natural resources such as natural gas is characterised by a boom-bust cycle, in which a rapid increase in economic activity is followed by a rapid decrease (Figure 3). The rapid increase occurs when drilling crews and other gas-related businesses move into a region to extract the resource. During this period, population increases and there is a modest increase in jobs outside the extraction industry[11] in construction, retail and services. When drilling ceases, either temporarily or permanently (because the commercially recoverable resource is depleted), there is an economic bust. Population and jobs leave the region.[12] Because of the costs of boom-bust cycles, communities and states anticipating this kind of economic cycle need to understand what will influence the pace and scale of drilling. In the case of HVHF, the pace and scale of drilling will determine the duration of the boom period of the cycle.

There are two ways to understand the pace and scale of drilling in a shale gas play. The first is based on an analysis of total potential natural gas reserves and the capacity of existing or anticipated technologies. For example, according to Engelder, the Marcellus might contain as much as 500 trillion cubic feet (tcf) of



Adapted from Tim Kelsey (2011), 'Annual Royalties in a Community'.

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Figure 3:

natural gas, and in a 2008 report with Lash, he estimated that perhaps 10 per cent of that gas (50 tcf) might be recoverable.[13] The following year, he estimated that recoverable reserves could be as high as 489 tcf.[14] More recent estimates of recoverable gas fall in the 200–300 tcf range. From a geologist's perspective, extraction of these total recoverable reserves could take decades.

Another perspective on the pace and scale of drilling looks at what are the likely firm strategies in response to their profit opportunities in particular shale plays and among potential extraction sites. For example, given a limited number of drilling rigs, they will be deployed in those places (within a gas play or across gas plays) where profits are most likely. The question for an energy company is not whether a well is viable in terms of potentially recoverable gas, but whether it is commercially viable — that is, will it make money for the operator (the owner of the mineral rights) and the drilling companies. An understanding of the choices made by operators and their subcontractors in a shale play requires an analysis of the costs and delivery rates of drilling operations, margins of commercial profitability, and corporate financial and competitive relationships.

Production in shale plays is unpredictable and only a small number of wells may be able to produce commercial volumes of gas over time without re-fracking, which is very costly. Evidence from the Barnett and Haynesville shale plays in the USA, for example, indicates that high initial production rates may drop off rapidly, making it difficult for operating companies to cover their finding and development costs. Industry investment advisors are cautious about the long-term productivity of the US natural gas plays. Their advice to investors is simple: 'Shale production is characterised by a steep decline curve early in its productive life.

The more oil and/or gas that you can make up front the better the economics.'[15]

And, according to geologist and investment adviser Arthur Berman, who has analysed production trends across US shale plays:

> … most wells do not maintain the hyperbolic decline projection indicated from their first months or years of production. Production rates commonly exhibit abrupt, catastrophic departures from hyperbolic decline as early as 12–18 months into the production cycle but, more commonly, in the fourth or fifth years for the control group. Pressure is drawn down and hydraulically produced fractures close… Workovers and additional fracture stimulations may boost rates back to previous levels, but rarely restore a well to its initial decline trajectory. More often, a steep hyperbolic or exponential terminal decline follows attempts to remedy a well's deteriorating performance. [16]

The possibility that only some wells will exhibit the hyperbolic production curves that are used to describe trends *across* wells in a shale play adds to the uncertainty for investors, operators and for the communities where drilling occurs.[17] Because shale plays may not produce the long-term commercial results indicated by the hyperbolic curves used by the industry to describe production (and encourage investment), they add to the financial risks already attendant to shale gas drilling.[18]

The risks and uncertainties facing investors and drilling communities have been exacerbated by the debt-driven character of development in shale plays. Operators have sought to buy up leases and hold them during a period when money and leases can be had cheaply, but this has put them into debt. The short-term prospects for reducing that debt are uncertain because of depressed US natural gas prices. A typical boom occurs during a period when energy prices are high. The current shale gas drilling boom in the USA, occurring during a period of low US natural gas prices, appears to be driven as much by the low cost of borrowing capital and global investment as by anticipated profits from the natural gas itself (if sold in the USA at current prices).

Despite the financial risks associated with natural gas drilling anywhere in the USA, the Marcellus Shale is considered to have among the best economics of the large US shale gas plays because of the potential richness of its reserves, but also because of low transport costs to the major domestic natural gas markets, inexpensively-acquired leases, and the absence of severance taxes. It also has significant drawbacks because of its proximity to populated areas, and the prospect of regulatory controls over water withdrawal and wastewater disposal as well as on the drilling process.

For those living in the Marcellus Shale region, gas operating company assessments of the commercial viability of wells and how to best exploit the resource have important consequences. Evidence from the Barnett Shale (in Texas) suggests that individual Marcellus wells may have short commercial production lives. Because the Marcellus play is large and geologically complex, however, the play as a whole is likely to have natural gas drilling and production over an extended period of time. Individual counties and municipalities within the region are likely to experience accelerated boom and bust cycles, while the region as a whole is industrialised to support continued drilling, storage, and transportation of natural gas. Counties where drilling-related revenues were never realised or now have ended may still be impacted by this *regional* industrialisation, such as truck traffic, gas storage facilities or pipelines. These more widely distributed impacts need to be taken into account when anticipating what effects natural gas drilling will have on communities, their revenues, and the regional labour market, as well as on the environment.

In anticipating some of the costs, it is possible to learn from the experience of already developed shale gas plays in the USA.

WHAT DO WE KNOW ABOUT WHAT OCCURS IN LOCAL COMMUNITIES AND REGIONS WHERE SHALE GAS DRILLING OCCURS?

Natural resource extraction industries typically play a small role in national economies. They are capital rather than labour intensive industries and their employment impact is tiny compared to industries such as retail or health services.[19] On the other hand, these industries have major impacts on the regions where production takes place. Shale gas drilling brings a short-term economic boom to the regions that experience it. As drilling companies move into a community, local expenditures rise on everything from car parts to pizza and beer. New jobs are created in construction, hotels and retail. Landowners receive mineral leasing and royalty payments and have extra spending money in their pockets. This increased economic activity is very welcome, especially in light of the 'great recession'.

In the USA, high volume hydraulic fracturing for shale gas has been taking place since the early 2000s, primarily in the western states. In the Marcellus Shale states of eastern USA hydraulic fracturing is even more recent. Even over this short period of time, however, experience is providing critical lessons. Each state has a distinctive set of issues because of differences in ownership (public vs. private land), climate, terrain, proximity of the play to population centres, and the availability of skilled labour. Yet despite these differences, the experience of shale gas regions can be used to identify common issues that are likely to arise with shale gas extraction. Among the most consistent local policy and planning issues across shale gas regions are those that derive from the boom-bust cycle of shale gas development, and the unpredictability of drilling and production activity across time and space.

Unfortunately, a full description of impacts on local communities is difficult to assemble because — with the exception of data on crime statistics — data must be assembled county-by-county, or agency-by-agency locally. There is an analysis of social and economic impacts common to counties in the Western States, where the local impacts of rapid development of shale gas drilling have been documented,[20] and anecdotal evidence from counties in the northern tier of Pennsylvania. Although not definitive, the accumulating body of evidence provides a picture of what localities can expect with natural gas extraction and what they should plan for. In the next section, the authors examine some of the most prominent of those impacts — on population, employment, and public services.

LOCAL SOCIAL AND ECONOMIC IMPACTS OF SHALE GAS DEVELOPMENT

At the heart of the social and economic challenges facing communities where natural gas development occurs is the rapid increase in a transient population using the region as a production site. Perhaps unexpectedly, this rapid increase in activity is not associated with a commensurate increase in population resident in the counties where the drilling occurs. The authors' analysis of population change in core natural gas drilling counties during the first decade of the

2000s indicates that the resident population in these largely rural counties has grown marginally if at all. There are various reasons that population growth does not occur in these core counties, but the most frequently cited are the absence of services, the higher cost of living, and the lower quality of life in an industrialised environment. For these reasons, the economic and social impacts of natural gas development are likely to be felt not only locally but regionally, affecting cities and counties in areas adjacent to the drilling localities themselves.

Another reason for the absence of new residents in drilling counties is the character of the workforce engaged in drilling and the transient demand for the services provided to drillers and drilling companies. As described by Jacquet,[21] the drilling phase of shale gas development usually depends on an out-of-state workforce. Although resident workers may be employed during the drilling phase as truck haulers or in service and construction jobs, even these jobs may be filled by workers who move into the drilling area while maintaining a permanent residence in another state. This in-migration of transient workers has been exacerbated by the great recession in the USA and the paucity of job opportunities elsewhere in the nation. In the case of the drilling workforce itself, this means a sudden influx of young men — some with families, many without. Some will be experienced gas field veterans, others will be those drawn from other places to the boom and the prospect of work.

In Sublette County Wyoming, for example:

> As the number of gas wells drilled *per year* (authors' emphasis) exploded from 100 in (the year) 2000 to more than 500 in 2007, the population of Sublette County swelled by 24%. During that same period, Wyoming's population grew by just 4%, indicating that workers and their families were flocking to the area to meet the new labor demands. The largest increase in population came from teens and young adults, aged 15 to 24, followed by adults aged 25 to 44.[22]

This short-term population influx also creates significant demands on public services.

According to Jacquet,[23] traffic on major roads increased, as did the number of traffic accidents, the number of emergency room visits, and the demand for emergency response services. In addition, local schools experienced increased demand as new workers entering the region enrolled their children. And, as demand for all manner of good and services increases and local businesses seek to exploit the boom, prices go up — not just for temporary residents, but for long-time local residents as well. Jacquet found that local prices in Sublette County increased by twice the national rate over a six-year period.

Williston North Dakota is an isolated prairie town where another shale gas boom is occurring, and it has been inundated by people from all over the USA looking for work. While they frequently find work, they have nowhere to live. The homelessness rate in the city has risen to at least 19 per cent, with many people living for long periods in temporary quarters.[24] Unfortunately, the boom-bust cycle of gas development discourages investment in the housing needed for this workforce. Local interviews indicate: 'Developers have been slow to build more apartments, largely because they got stung by the region's last oil boom that went bust in the 1980s.'[25]

The price inflation characteristic of shale boom areas especially affects rental housing. Evidence from across shale plays indicates that rents rise dramatically in drilling areas. Local long-term renters who cannot afford their apartments any longer are displaced, and may seek housing assistance from local government. Hotels and motels fill up with transient gas drilling workers.

This increased demand for hotel rooms may benefit hotel and motel owners and local restaurants, but it hurts other local businesses, as hotels may have few rooms available for a more traditional clientele: business travellers, recreation seekers, and tourists.

In the long run, given the population declines suffered by many communities in the Marcellus region, this influx of new people may be welcome. Some newcomers may like the area and decide to stay. According to a recent US Associated Press story,[26] the small state of Wyoming has seen population increases and an unemployment decline over the past decade, especially in communities near gas drilling areas. But for local governments, this population influx comes with added costs, both in the short run and in the long run.

The consistent theme is that local governments — counties, cities, townships, villages — are subjected to a wide range of demands for new services or increased levels of service, and that the administrative capacity, staffing levels, equipment, and outside expertise needed to meet those demands are beyond anything that has been budgeted.

Infrastructure impacts

One critical area of impact is on local roads and bridges. As Randall points out:

> Dust, noise, and road damage from industry truck travel are tops on the list of citizen complaints in areas where gas is extracted via shale gas drilling. A typical Marcellus well requires 5.6 million gallons of water during the drilling process, in almost all cases delivered by truck. Liquid additives are shipped to the well site in federal DOT-approved plastic containers on flatbed trucks; hydrochloric acid and water are delivered — and flowback is hauled away — in tanker trucks. Millions of gallons of liquid used in the short (weeks-long) initial drilling period account for half of the estimated 890 to 1340 truckloads required per well site. Because of its weight, the impact of water hauled to one site (364 trips) is the equivalent of nearly 3.5 million car trips. Few roads at the town level in New York State have been built to withstand this volume of heavy of truck traffic.[27]

Pennsylvania state officials report scrambling to re-route trucks in the wake of rural roads sometimes rendered impassable for local motorists or emergency responders, while sources in the Barnett Shale region of Texas cite early deterioration of city streets that increases the burden on taxpayers. That is because, even though access roads to the well sites are built and maintained by the operators, many of the journeys made by all those trucks are on public roads. Most roads, especially the rural roads that predominate in the Marcellus region (and especially under Winter and Spring freeze-thaw conditions), are not designed to withstand the volume or weight of this level of truck traffic.

In Pennsylvania, local governments can utilise State Department of Transportation protocols to post weight limits and require permits and bonding of overweight truck operators, an incentive for the operators to either do the excess maintenance themselves or pay for damage to the roads. However, operators are inclined to post bonds only in municipalities or counties where they have well sites, while the trucks travel much longer routes through other towns and counties. Their roads are left vulnerable.

Recommendations from those in

already developed shale plays centre on the planning, posting, and enforcement of truck routes that minimize the intrusiveness and damage caused by high-volume truck traffic, and on local Road Use Agreements (RUAs) or state-level fees that support accelerated road maintenance while gas drilling or production activity is underway.

These need to be supported by comprehensive traffic impact studies, well-documented baseline data backed by video and photographs of pre-development road conditions, and specialized legal advice — processes that require additional staff and, for most communities, funds for consulting engineers and lawyers as well.

Whatever regulation and technical assistance the province or state may provide, many of the costs of drilling fall on local governments. And, these costs are likely to fall on some localities where drilling makes no appreciable contribution to the economy either through job creation or tax revenues. Contemporary shale gas drilling is likely to have both intense local impacts for the drilling period, and longer-term regional consequences as well because of the widespread industrialisation that accompanies contemporary hydraulic fracturing.

Regional industrialisation impacts

Well pads are not the only feature in the industrial landscape brought about by shale gas development. Water extraction sites must be developed to fill trucks transporting water to the well pads. After extraction, the gas has to move from the well sites to the main transmission lines via a network of pipelines and compressor stations. Toxic flowback and produced water from the wells has to be transported to treatment facilities, which must be built to handle its particular array of toxic waste.

These elements of the industrial landscape will be located where geologic or logistical factors dictate, but not necessarily in the jurisdictions where drilling is currently taking place or production (and therefore tax revenue) is being generated. For local governments, the same questions as for well sites or pipeline infrastructure apply to these facilities: Who — the state, the province, or the localities — is to regulate them, and monitor and enforce standards; what staffing and resources will that require; and how shall the funds to support those efforts be provided?

These facilities typically include:

- 'Man camps' (essentially caravan sites) for short-term out-of-state workers
- Depots for equipment
- Staging areas
- Gravel quarries
- Water extraction sites
- Wastewater treatment plants capable of handling toxic material
- Injection wells
- Disposal areas (landfills)
- Gas storage facilities.

Connecting all these facilities and services are rail spurs and thousands of heavy trucks.

These industrial facilities create a wide range of potential environmental hazards and stressors, all of which have implications for the regional economy and adjacent industries, such as tourism and agriculture. For example, apart from the dangers inherent in a widespread network of pipes full of methane or in high-pressure equipment generally, noise is a major concern related to compressor stations: they produce noise levels in the 85 to 95 decibel range. These levels are at or above the US Occupational Safety and Health Administration (OSHA) threshold of safety for an 8-hour day, and compressors work a 24-hour day. These environmental stressors can have an effect on nearby citizens, adjacent property values, and on other industries in the vicinity, particularly agriculture and tourism.

In the USA, regulation of this extensive industrial infrastructure is likely to occur at a level of government above that of the locality. Localities may have a role in the permitting of pipeline routes along city/county rights-of-way. Local government may also require filings and notice to abutters, and demand incident reporting and filing of as-built drawings for emergency planning. For compressor stations, local regulation may be able to establish setbacks, maximum noise levels, fencing and landscaping requirements, and enhanced standards for units adjacent to residential areas.

If not reused, flowback fluids from the hydro-fracking process or the produced water from producing wells must be removed from the well sites by trucks and transported to treatment facilities or injection wells. These facilities, too, may be subject to permit or construction standards that are set or implemented at the local level. All of these local or regional activities require expertise, administration, monitoring, and enforcement capacity, and all entail planning and public administration costs.

One example of the impact industrial facilities may have on a region is provided by the proposed gas storage facility in the Finger Lakes region of New York State, a major area for tourism because of its scenic beauty, small towns and vineyards. This facility is being planned by Inergy Midstream, LLC for the former US Salt plant just north of Watkins Glen, New York, with underground storage for 1.45 billion cubic feet of natural gas. The new owners propose to add an up-to-88.2 million gallon liquid propane storage facility, also underground, plus a 14-acre, 92 million gallon brine pond on the surface.

The site for this major facility is near the intersection of two gas transmission pipelines and, as a salt mine, is an appropriate natural gas storage site. But Watkins Glen is in Schuyler County, which is not part of the 'fairway' — the purported 'sweet spot' for Marcellus drilling in New York, so it is not likely to obtain local tax revenue from well production. Whatever the plant may contribute in the way of local taxes, Watkins Glen currently depends on revenue from Finger Lakes tourism, attendance at its famous road race, the local wine industry and agriculture. Consequently, the potential hazards to air or water from such a facility, or the prospect of a fire or explosion, are particularly troubling to local policy makers. On the other side of the equation, this capital-intensive plant operation is expected to produce only ten jobs after its construction.

Officials in regions already experiencing shale gas drilling encourage planning and the development of fewer, centralised locations for all these industrial functions, in order to minimise the impacts on local communities. Because hydraulic fracturing entails a regional industrial infrastructure, this planning will necessarily require inter-county cooperation and state assistance.

Finally, the regulation of whatever facilities are constructed will be a responsibility shared between the state and local governments, in ways as yet unclear. Localities will have to allocate resources to negotiating with the state — and many departments of state government are involved — for agreements that protect their interests and those of their citizens.

HOW ARE LOCALITIES RESPONDING TO THE CHALLENGES POSED BY SHALE GAS DRILLING?

Different communities respond differently to the prospect of natural resource extraction in their region, as do their policy makers. One factor in these differing responses lies with citizens' familiarity or unfamiliarity with the industry. Another appears to be a difference between a 'dominion' and a 'stewardship'orientation toward the natural world. In a survey of 6,000 households in the drilling regions of New York and Pennsylvania, respondents who perceive lower risks from hydraulic fracturing think of the natural environment in terms of its utility, while those who perceive higher risks see humans as part of — and responsible for — the ecosystem. The survey indicates that most residents value the quality of life in their largely rural communities and they are concerned about the lack of jobs, but they weigh those concerns differently. Although there is a large middle group of respondents who are not clear about what will happen to their communities, there are sizable groups that are polarised in their expectations about the impacts of shale gas development, and that trust different sources of information on what is occurring. This bodes a fractious political environment for local officials, and suggests the need for careful planning: 58 per cent of those surveyed think that the negative impacts associated with hydraulic fracturing can be prevented, but only 22 per cent indicate that those negative impacts can be repaired once they occur.[28]

In the USA shale gas plays that have been in operation for some time, local government officials have the benefit of looking back on their experience and on what they think are the most important measures that communities can undertake when faced with the challenges posed by natural gas drilling. Their recommendations emphasise efforts to educate the general public and landowners in particular, and to make the process of natural gas development as transparent as possible.

According to these experienced local officials, administrative costs for all manner of planning, permitting, monitoring, and enforcement activities rise, as does the cost for computer systems to support them. So do demands on the police, courts, jails, services to displaced renters, and other social services. To these are added demands on the school system, on the public health department, and on the healthcare system generally. Fire and emergency services must be prepared for the kind of fire, accident, or spill incident that drilling operations can produce, requiring new equipment and training, though many communities have volunteer or 'call' operations that may not ever be prepared, or willing, to take on a major hazardous materials incident.

A Clinton County Pennsylvania review of the early impacts on their departments turned up one additional factor in the costs to government: losing their employees to private sector jobs in the gas play. That adds the cost of recruiting and training new staff, and the need to increase salaries to attract or retain them.

All this suggests to local governments three crucial elements of preparation:

1. **The need for baseline data.** Without the baseline data on roads, water treatment, rents, traffic, use of government equipment, etc, local governments cannot hold the well operators or their subcontractors accountable for the increased cost to local services that their activities generate, nor can they make a good case for relief from the state.
2. **The need for a dedicated revenue stream from gas production.**
3. **The need to budget for future costs.** Just as the unfolding of demands on localities from the effects of shale gas development may not correspond to the flow of tax revenue from gas production or lease/royalty payments to

landowners, so the effects of shale gas exploration may last far longer than the boom in drilling activity in any given locality. Lowering property taxes during the revenue boom may only lead to raising them even more when the full effects on local government operations are realised. Better to utilise the variety of budgeting instruments — fiscal impact fees, trust funds, capital reserve funds and a healthy fund balance — designed to stabilise the tax rate by setting aside monies to defray future costs.

WHAT DO WE KNOW ABOUT THE LONG-TERM ECONOMIC EFFECTS OF HVHF SHALE GAS DEVELOPMENT ON LOCAL AND REGIONAL ECONOMIES?

In this paper, the authors distinguish between the short-term impacts of HVHF natural gas drilling — on jobs, revenues, and costs to communities — and the long-term consequences for economic development. Economic development (as distinct from economic *impact*) is defined here in terms of indicators that show whether a county or region's population has an improved standard of living, job opportunities, and the kind of diverse economy that can weather downturns in any particular industrial sector.

It is evident that natural gas drilling will create work in shale gas regions during the drilling phase. The population flowing into the region will create demand for retail businesses and in hospitality industries, such as hotels and restaurants. Construction activity will also increase. Analyses of what kinds of jobs are likely to be produced during the drilling boom underscore that these three sectors are most likely to create jobs outside of the drilling industry itself. However, as Barth notes,[29] there are reasons to be cautious about the natural gas drilling industry as a route to long-term economic development, especially in rural counties. This caution arises from studies that show that rural regions whose economies are dependent on natural resource extraction frequently have poor long-term development outcomes. In some cases, they may end up worse off after a boom-bust cycle than they were before it started. While this may seem surprising given the economic activity that floods into a region during the drilling phase, there are some readily understandable reasons for poor long-term prospects.

First, the crews who come into a region place demands on a limited housing stock and housing prices rise, driving low income renters to leave the area, and creating a potential labor shortage for other businesses. This type of displacement can be seen in Northern Pennsylvania, where low-income families are being displaced by drillers in the local rental markets around the drilling sites.[30]

While competition for labour creates some short-term winners among locals, such as truck drivers, it also raises costs for other businesses in the region as labour costs for those occupations rise. For example, dairy farmers in the Marcellus region of northern Pennsylvania and the southern tier of New York, who are already in a marginal economic situation, are being further squeezed because of rising costs for transporting their milk to the dairies. These businesses may go under during the drilling phase, leaving the region with fewer businesses outside of gas drilling, and thus a less diverse and more volatile economy.

Economists refer to the situation in which short-term but high-wage resource extraction leads to a poor business climate for other businesses as 'crowding out'. While crowding out particularly affects businesses that require a reliable low cost labour supply (agriculture, tourism, or retirement communities, for example), even higher wage businesses such as manufacturers may be deterred from investing in a resource extraction economy. Higher housing costs, labour competition and social issues make the resource dependent region less attractive to other employers than alternative locations.

Resource extraction regions are also infamous for having serious governance challenges. Volatile revenue leads to poor government planning and a lack of accountability, even as demands on government rise and may continue to persist long after the tax revenue from the drilling phase has dried up. When the local boom ends, the human and physical infrastructure built to support a boomtown population is left for a much smaller population to support. As Feser and Sweeney describe in their study of such communities' experience with out-migration and population loss:

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> During the boom period, the county's physical infrastructure was planned and installed to accommodate an expanding population. The nature of infrastructure such as roads, sewer and water facilities, and schools is that once it is built, it generates ongoing maintenance costs (as well as debt service costs) even if consumption of the facilities declines … the departure of mine workers and higher income, mobile professionals left the burden of paying for such costs to the remaining smaller, lower-income, population.[31]

In general, US counties that have hosted drilling activities show evidence of population loss after the drilling ends. For example, counties in New York and Pennsylvania with significant natural gas drilling (1994–2009) are characterised by greater population loss when compared with similar rural counties in their respective states.

Finally, although there are some local winners in a resource extraction economy, in the long term their numbers appear to be outweighed by the local losers. After the initial construction and drilling phases, there are very few well-paying, stable jobs available in the production phase or in the industrial facilities servicing the regional industry (such as gas storage sites). As a result, income inequality tends to increase in natural resource extraction counties.

Evidence suggesting caution in projecting long term economic development from natural gas drilling comes from a study of 26 counties in western US states that have based their economic development on the extraction of fossil fuels (natural gas, oil, and coal).[32] This study shows that these counties (those that have at least 7 per cent of their total jobs in resource extraction industries) have not performed as well as similar counties without extraction industries. Both their average annual growth in personal income and their employment growth (1990–2005) were lower than their peer counties without extraction industries. These energy-dependent county economies exhibited a set of similar characteristics. They had:

- Less economic diversity
- Lower levels of educational attainment
- More income inequality between households
- Less ability to attract investment.

Also, a majority of the energy industry focused counties (16 of the 26) lost population during this period. Though the reasons for this loss are not fully documented, anecdotal information suggests that they may include the higher cost of living in these counties and the displacement of residents who do not want to live in an industrialised landscape — for example, retirees.

In part, the difference between the extraction-focused counties and other counties has emerged because new service-based industries, especially tourism, have been growing in rural western US counties and are creating more jobs than extraction industries. The extraction counties do not attract as many tourism dollars as counties without extraction industries. The picture is uneven, however. While energy extraction counties underperformed in terms of the growth of real personal income, employment, and population, they outperformed their peer counties in terms of growth in earnings per job and per capita income. But for these measures — average earnings per job and per capita income — there was only a modest positive difference (0.6 per cent per year from 1990 to 2005).[33]

In general, the research that has been done on resource extraction in rural areas offers no guarantee that counties where fossil fuel reserves are developed will have a significant long-term advantage over counties where they are not.

WHAT IS MOST IMPORTANT IN EVALUATING THE ECONOMIC CONSEQUENCES OF SHALE GAS DRILLING?

If one wants to understand how natural gas drilling will affect communities, the economic impact models typically used to project potential job creation give only a fraction of the information that is needed. Economic impact models do not address major questions about the cumulative costs to communities that come with drilling, and about how the pace and scale of drilling will affect royalty payments and the tax revenues to pay those costs. There are also potential negative consequences for other industries located in the drilling region, including agriculture and tourism. A realistic assessment of how natural gas drilling will affect the regional economy must have a framework that has been missing from IO models, one that looks at long-term consequences and cumulative impacts.

In the case of high volume hydraulic fracturing for shale gas, the evidence from across shale plays[34] and from broader studies of natural resource dependent economies indicates that one should be cautious about expecting positive long-term outcomes (beyond 5–10 years). Natural resource extraction has a poor record of leading to strong, diversified regional economies.

In thinking about and responding to the environmental and economic challenges posed by shale gas drilling, elected officials and other policy-makers need to start with the realisation that natural gas is a non-renewable resource. Good stewardship from an environmental perspective requires assessing the long-term costs and benefits of HVHF technologies and their implications for the natural and human environment in which gas extraction occurs. Although the economic consequences of HVHF gas drilling have been counter-posed to environmental concerns, positive economic outcomes cannot be taken for granted. Thus, elected and appointed officials also need to take responsibility for careful management of the local and regional economies affected by HVHF gas drilling and their longer-term sustainability. This means anticipating what may occur in the short term during a boom, and in the longer term when drilling ends. Both of these periods will present difficult issues. It is only by anticipating what may occur, planning for change, and communicating a concrete vision for the future that policy makers can make the kinds of choices that will stand the test of time. There will be no second chances.

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[P1]Authors please insert callout for Figure 1 within the text.
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[P3]Author: we assume that this is the same as ref 12.

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The economic impact of shale gas extraction: A review of existing studies ☆

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ABSTRACT

Recent advances in drilling technology have allowed for the profitable extraction of natural gas from deep underground shale rock formations. Several reports sponsored by the gas industry have estimated the economic effects of the shale gas extraction on incomes, employment, and tax revenues. None of these reports has been published in an economics journal and therefore have not been subjected to the peer review process. Yet these reports may be influential to the formation of public policy. This commentary provides written reviews of several studies purporting to estimate the economic impact of gas extraction from shale beds. Due to questionable assumptions, the economic impacts estimated in these reports are very likely overstated.

Contents

1. Introduction

Natural gas has historically been extracted from shallow gas wells using traditional drilling methods. Within the past decade, technological advances such as hydraulic fracturing and horizontal drilling have for the first time made profitable the extraction of natural gas from deep underground shale rock formations. Both economic benefits and environmental risks of such nonconventional gas extraction accrue to regions within close proximity of shale gas deposits. Site preparation, drilling, and extraction generate local economic revenues and provide local employment opportunities. But the drilling process requires large quantities of water and the backflow (frac water) requires careful handling and can threaten the natural environment.

Due perhaps to uncertainties over the size of these economic benefits and environmental costs, public response to the new extraction process has varied. Areas familiar with the gas extraction industry such as central Texas and western Pennsylvania have applied existing environmental and safety regulations to the new extraction methods. But New York, where the energy industry is relatively unknown, placed a moratorium on shale gas extraction until it has sufficiently studied the environmental risks.

To help facilitate favorable public policy, the natural gas industry has sponsored several research efforts that estimate the economic benefits of shale gas extraction. These reports, not published in economic journals but instead made available on the web sites of the gas industry, estimate the increase in local and state revenues, employment, and tax revenues from gas extraction. In some cases, these reports are authored by private

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consulting firms. In other cases, these reports are authored by research economists serving as private consultants and affiliated with well known research universities. In these latter cases, the economist's institutional affiliation is often featured prominently on the cover to add credibility and sense of objectivity to the report even if the economic researcher relinquished final editing duties to the funding organization. One concern for the objective formation of public policy is the possibility that local policymakers view the institutional affiliation of the private consultants as evidence that the report represents credible peer reviewed economic research. If those policymakers are unacquainted with the economic research methods used in these reports and are therefore unable to judge the validity of the results, then the economics profession has not served the policy making community.

This commentary reviews a collection of reports purporting to estimate the economic impact of gas extraction from shale beds. The focus is on reports sponsored by the gas extraction industry and issued with academic institution affiliation. For example, Considine et al. (2009 and 2010) were both funded by the Marcellus Shale Coalition (the shale gas extraction industry in Pennsylvania) and feature the Penn State logo on the title page. CBER (2008) was sponsored by four gas extraction firms and features the University of Arkansas logo on the title page.

The hope is to help fill the void created by the lack of a peer review of these reports. The credibility of economic research originates not from institutional affiliation but from the peer review process utilized by all respectable academic journals. This review process ensures fairness, promotes the candid exchange of ideas, and often improves the quality of the work.

The next section summarizes and critiques these three reports. Section 3 provides a brief overview of other known economic impact studies from gas extraction generated from private consulting firms unaffiliated with academic institutions. Section 4 offers a broad critique of the methodology used by these six reports to evaluate "economic impact." Section 5 discusses benefit-cost analysis, a common alternative method for evaluating the economic impact of an activity such gas extraction. Section 6 offers a comment on the use of a severance tax on gas extraction, and is followed by a brief conclusion.

2. Reports Released with Academic Affiliation

A delineation is made between three reports that were released under academic institution affiliation (Considine et al., 2009, 2010; CBER, 2008) and three that were released by private consulting companies unaffiliated with an academic institution. The delineation is based upon the premise that institutional affiliation can denote the expectation of unbiased and high quality research to policy makers and other readers. The institutional affiliation carries with it the expectation that research should satisfy not just the standard for reports from the consulting industry, but instead achieve some higher level of academic standard.

2.1. An Emerging Giant: Prospects and Economic Impacts of Developing the Marcellus Shale Natural Gas Play

Considine et al. (2009), affiliated with Penn State, estimates the economic benefits of extracting gas from the Marcellus Shale in western and northern Pennsylvania. Pennsylvania is depicted to be rather unique in the United States due to its (1) supplies of natural gas both in shallow wells and imbedded in deep shale formations, (2) availability of subterranean reservoirs to store natural gas imported from the southwest United States for later consumption, and (3) proximity to several large population centers along the eastern sea board. This latter aspect has caused the price of natural gas in Pennsylvania to generally exceed that in most other areas of the country.

The economic impacts of shale gas extraction are estimated using the IMPLAN input–output model. The IMPLAN model has been used by consultants, government officials, and economic researchers to address a variety of research questions. Because shale gas extraction is relatively new to the Pennsylvania economy, the IMPLAN model had to be adjusted using a process developed by Miller and Blair (2009). This process requires detailed expense amounts from the industry. This information was gathered via a survey of firms currently in the process of extracting gas from the Marcellus shale. Based on responses to this survey, the report estimates that 95% of industry spending occurred within the commonwealth of Pennsylvania.

IMPLAN results suggest spending by the shale gas extraction industry is responsible in 2008 for $2.263 billion in economic activity, the creation of 29,284 jobs, and the payment of $238.5 million in state and local taxes within the commonwealth of Pennsylvania. The report also estimates the number of new wells drilled as a function of the price of natural gas using quarterly time series data from Barnett shale activity in Texas. Econometric results suggest a 1% increase in the price of natural gas is estimated to increase the number of new wells drilled by 2.70%. This estimate and future price data from the New York Mercantile Exchange are then used to forecast the number of wells drilled in Pennsylvania over the next decade. Results suggest the number of wells drilled in Pennsylvania will increase from about 1000 in 2010 to 2800 in 2020. These results are applied to estimate the effect of a severance tax on gas extraction in Pennsylvania. Results suggest a tax set equal to that levied in West Virginia will cause the number of future wells drilled to decrease by 30%.

Several aspects of Considine et al. (2009) are credible. The historical and technological sections appear to report an accurate background of the industry. The survey data had a rather poor response rate (only 7 of 36 firms responded), but as these firms represented 59% of all drilling in Pennsylvania it is appropriate to extrapolate survey findings to the entire industry. It is worth noting that itemized industry expenses with names and locations of suppliers are highly proprietary information. A research economist unaffiliated with the gas industry would not gain access to such data. The IMPLAN model, as mentioned by the authors, is perhaps the most common input–output model in the country and is used by consultants, government officials, and research economists. The technique described by Miller and Blair (2009) for estimating direct spending of a new industry is appropriate assuming that itemized expense data are available, as they were for this report. One concern is that the IMPLAN model works best when considering modest "marginal" changes in economic activity. The addition of billions in direct spending will likely alter the relationships within the model that could very easily alter estimated impacts.

The report has three major shortcomings that all serve to overstate economic benefits that would need to be addressed to warrant journal publication. The first is the assumption made that all lease and royalty payments to private households are spent by households on goods and services produced in Pennsylvania in the same year that those payments were received. The importance of this assumption cannot be understated—in 2008 such payments to households represented 68.6% of all industry direct spending. Households can be expected to save some of these windfall earnings. Given the fluidity in the international market for financial capital, additional savings by Pennsylvania households are unlikely to be lent to Pennsylvanians to facilitate increase investment or consumptive expenditures within Pennsylvania. That *none* of these windfall earnings are assumed to be saved (or used to pay down debt) by households seems implausible and is inconsistent with the economics literature. The behavioral economics literature, for example, contends that households are more likely to save (or reduce debt) after receiving large windfall payments relative to receiving small sums (Thaler, 1990). An economic impact study of shale gas extraction in Louisiana (Scott, 2009—summarized below) assumed that households spend only 5% of windfall earnings within the year received. This report should use a more realistic assumption regarding the marginal propensity to consume windfall gains. Although the present estimated economic impacts would obviously decrease substantially, future impacts would likely increase as the spending from household lease and royalty payments received in the present are spread across many future years rather than spent entirely in the present year.

The second shortcoming in this report is the lack of a detailed description to support the assumption that 95% of all industry expenditures, including lease and royalty payments to households, occurred within Pennsylvania. The survey helped identify the location of suppliers to the industry, but payments to suppliers comprise only 31.4% of all spending. Households receive the lion share, and any amount not saved may have facilitated purchases of goods or services produced outside of Pennsylvania (such as vacations, new automobiles, or jewelry). The report suggests the "company profile databases Reference U.S.A." was used to determine the geographical location of each firm receiving direct spending. But the report is silent on the assumptions necessary if, for example, a given firm operated only a branch office in Pennsylvania but imports parts and supplies from other states or countries. One report suggests that 70% of workers in the industry originate from other areas of the country (Allegheny Conference, 2010). The assumption that 95% of direct spending by the industry and royalty-receiving households took place in Pennsylvania is therefore under supported. A detailed description of the process used to identify the location of direct spending would alleviate this concern.

The third shortcoming, one that I am sure the authors would agree with, is the assumption made that the quantity of well drilling is estimated solely as a function of the contemporaneous price of natural gas. The assumption that the price of natural gas is exogenous in Texas is entirely plausible, but omitted variables are quite likely to lead to a biased estimate of the relationship between price and well drilling. Omitted variables could include the expected future price (which could influence both current price and investment expenditures on drilling), the state of drilling technology, the state of the macro economy, and the number of wells drilled in a previous period (suggesting a time series). That the number of wells drilled in Texas had to be "calibrated" for use in Pennsylvania is highly suggestive that variables other than the current price explain drilling quantity and that these variables take on different values in Pennsylvania than they do in Texas. These other variables could very easily be correlated with price, implying a bias in the estimated coefficient on price. Because the econometric model is utilized to estimate the effects of a severance tax on natural gas, a discussion that could influence public policy, greater attention should be devoted to estimating an unbiased relationship between price and well drilling. The current estimate is unconvincing and potentially misleading.

Also, in the tax section, the comparison between Pennsylvania and West Virginia is fragile. Certainly differences other than the regulatory climate between the two states describe differences in gas extraction, such as the proximity to major markets along the east coast. The report does not provide convincing evidence that conditions experienced in West Virginia are the direct consequence of a severance tax.

2.2. The Economic Impacts of the Pennsylvania Marcellus Shale Gas Play: An Update

Considine et al. (2010) updates the economic impacts of shale gas extraction on the Pennsylvania economy. The Penn State logo is again featured prominently on the cover page. This update is also based on a survey of firms in the industry. But rather than asking firms to report detailed expenses as was done for the original report, the updated survey asks firms to provide spending levels in a few broad categories (lease/bonus spending, exploration costs, drilling expenses, gas processing costs, royalties paid and other spending). Results from this survey suggest spending in these categories increased from $3.22 billion in 2008 to $4.54 billion in 2009. This increase in spending is attributed to increases in drilling expenses and gas processing expenses in 2009.

The expense reports gathered for the original report (Considine et al., 2009) were used as a benchmark to allow IMPLAN to estimate the economic impacts. Results of the IMPLAN model suggest the Marcellus gas industry contributed $7.17 billion to the Pennsylvania gross output—implying a spending multiplier of 1.90. This multiplier is about 25% higher than that found for other shale industries in the country—the authors attribute this difference to the accuracy of each surveyed firm's expense report relative to past studies. A second estimate of economic impact, the value added to the Pennsylvania economy from the gas industry, is estimated at $3.88 billion in 2009. The value added metric subtracts inter-industry purchases from gross output. The industry is also estimated to have contributed 44,098 jobs to the Pennsylvania economy in 2009 and paid $389 million in state and local taxes.

This report also estimates the quantity of natural gas produced in Pennsylvania over the coming decade. The number of vertical and horizontal wells drilled in 2010 and 2011 are estimated based on industry responses to the survey. The number of wells drilled beyond 2011 is based upon the econometric model reported in the original 2009 report and discussed above. This model forecasts that 3500 wells will be drilled in 2020. Based on these assumptions, the report suggests natural gas production in Pennsylvania will increase from 1 billion cubic feet per day in 2010 to 13.5 billion cubic feet in 2020. The economic impact of this gas production is estimated at $18.85 billion in value added, $1.87 billion in state and local taxes, and nearly 212,000 jobs in 2020.

All three shortcomings that weakened the validity of the first report are imbedded in this update as well. The assumption is still made that all lease and royalty payments are spent by households within the year they are received, the assumption that 95% of all direct expenses occur within Pennsylvania is still made, and the econometric model used to forecast the quantity of well drilling solely as a function of the contemporaneous price of gas is still applied. These three shortcomings, once again, potentially undermine the accuracy of all results.

2.3. Projecting the Economic Impact of the Fayetteville Shale Play for 2008–2012

CBER (2008) estimate the economic impact of shale gas extraction in Arkansas. The report features the logo of the University of Arkansas on the cover page, but adds a disclaimer that although the gas industry sponsored the research, the conclusions reached were not influenced by outside parties. This research is based on a survey of several firms extracting gas in Arkansas, and as above uses the IMPLAN model to estimate the effect of gas extraction on economic output and employment. Specifically, shale gas extraction is estimated to increase gross revenues in the state of Arkansas by $2.6 billion in 2007 and generate 9533 jobs. These impacts are also forecasted for years 2008 through 2012. These forecasts are based on planned investments as identified by industry in the survey.

This study also estimates the impact of a severance tax on natural gas extraction. Rather than relying on a potentially misspecified econometric model, this study utilizes responses from the industry survey. One survey question asked firms how a 5% severance tax would affect planned investment expenditures. Responses suggested firms would decrease investment expenditures by an average of 13%. For comparison, Considine et al. (2009) estimate a 30% reduction in investment expenditures from the severance tax.

3. Other Studies of the Economic Impact of Shale Gas Extraction

Three similar reports use the same approach as that used in the reports discussed above to estimate the economic impact of shale gas extraction on state and local economies. These reports are issued by various consultants that are not affiliated with a prestigious academic institution. One of these reports estimates the economic impact for the state of Louisiana (Scott, 2009), one for the Dallas-Fort Worth regional economy (The Perriman Group, 2009) and one for Broome County, NY (Weinstein and Clower, 2009).[1] Table 1 summarizes the

[1] For convenience, all of these reports can be accessed at http://groundwork.iogcc.org/topics-index/shale-gas/topic-resources (accessed 7/13/2010).

Table 1
Other studies, a comparison of assumptions.

Shale play	Estimated impact	In the year	To the economy of	Assumptions
Marcellus	$4.2B in output 48,000 jobs	2009	Pennsylvania	100% royalties spent immediately "The locations of all these suppliers and income recipients were determined using the company profile databases Reference U.S.A. and Manta, which also provided the economic sector for each purchase" (95% of direct spending in state)
Marcellus	$8.04B in revenues 88,588 jobs	2010	Pennsylvania	100% royalties spent immediately "The locations of all these suppliers and income recipients were determined using the company profile databases Reference U.S.A. and Manta, which also provided the economic sector for each purchase" (95% of direct spending in state)
Barnett	$11B in revenues 111,131 jobs	2008	Dallas/Ft. Worth Area	"The amounts were fully adjusted to reflect those funds that are paid outside the region (and state) and are further reduced to account for out-of-area spending, savings, and taxes."
Hayensville	$2.4B in revenues 32,742 jobs	2008	Louisiana	All direct spending in state Assumes households spend 5% of lease and royalty payments in 2008.
Fayetteville	$2.6B in revenues 9533 jobs	2007	Arkansas	Survey asks firms to report state of residence of employers, but not whether spending occurs in state or out of state.
Marcellus	$760M in revenues 810 jobs	2000 wells over 10 year period	Broome County, NY	Assumptions regarding percentage of drill spending in local economy not stated
Marcellus	$2.06B in revenues 2200 jobs	Gas production per year	Broome County, NY	Assumes 15% of royalty earnings remain in local economy

findings of all six reports. Included in the table is a description of each report's two assumptions regarding direct industry spending. The first assumption is what percentage of direct industry spending is assumed to occur within the state or local economy. Recall that the two reports summarized above assumed 95% of all direct spending occurs within the commonwealth of Pennsylvania. The assumption that most or all spending occurs within the local or state economy is shared by most of these other reports. One report assumed that only 15% of direct industry spending occurred within Broome County, New York (this study is also the only to delineate between the economic impacts of drilling and that of extraction).

The second key assumption is what percentage of lease and royalty payments are saved by households. The reports above and almost all reports summarized in Table 2 assume all lease and royalty payments received by households are spent in the year in which they were received. The Louisiana study is unique by assuming households save most of these windfall earnings and spend only 5% each year.

One additional report not summarized in Table 1 also estimates economic impacts (Murray and Ooms, 2008). Rather than using a model such as IMPLAN to forecast economic impacts, this report compares historical data on population, incomes, and employment over a 16 years in four regions of the country. The first studied region is Denton County in Texas where gas has been extracted from the Barnett shale since 2001. The second and third are Faulkner County and White County in Arkansas within the Fayetteville shale play. Gas exploration began in this region in 2002 but only 180 wells have been drilled as of 2006. The final region is the counties that comprise the 10th Congressional District in northeast Pennsylvania, where only limited shale drilling occurred prior to 2006. The data provided are divided into two periods. The first period is 1990–2000 when none of the regions experienced gas drilling or extraction. The second time period is 2000 to 2006 when gas extraction was active in three of the four regions. Differences in growth rates of populations and per-capita incomes experienced in counties with and without gas extraction serves as a crude estimate of the economic impact of shale gas extraction.

The authors of this report unfortunately draw the wrong conclusions by describing changes in economic variables in shale areas as "tremendous" and those in non-shale areas as "negligible". The data simply do not support these conclusions. Table 2 provides the average annual percentage change in population, median household income,[2] and employment in each of these four regions across both time periods used in the original report. Statistics marked in bold are assumed to represent regions or time periods where shale gas extraction was active. If gas extraction impacted the economy, then we would expect to see populations, incomes, and employment rise at greater rates in bold areas than in non-bold areas.

There are a host of economic variables that could explain differences in these variables across time, so comparing within-region statistics in the 1990–2000 period with those of the 2000–2006 period would yield no insight into the economic effect of gas extraction. The only way to make use of these data is to consider differences in differences. Did the local economies in Texas or Arkansas experience a different change from the early to the latter time period than the local economy in Pennsylvania?

In Denton County, the average annual rate of population growth did not change across the two periods. But in Arkansas, the average annual population growth rate decreased in the two counties by 1.5% (from 4.3% per year to 2.8% per year) and 0.9% (from 2.2% to 1.3%). Compare these experiences with the case in Pennsylvania where the average annual population growth rate decreases by 1.3% (from 1.4% to 0.1%). Assuming that no other economic or demographic variables affected Pennsylvania any differently than these other areas, then we can estimate that shale gas drilling increased the annual population growth rate by between 1.3% and a negative 0.2%.

Table 2
Average annual percent increases. (bold implies active shale gas extraction).

Region	1990–2000	2000–2006
Denton County, Texas Barnett Shale (began 2001)	Population ↑ 5.8% Median HH Income ↑ 5.8%	**Population ↑ 5.8%** **Median HH Income ↑ 2.5%**
Faulkner County, Arkansas Fayetteville Shale (began 2002)	Population ↑ 4.3% Median HH Income ↑ 6.1% Employment ↑ 4.8%	**Population ↑ 2.8%** **Median HH Income ↑ 1.5%** **Employment ↑ 1.1%**
White County, Arkansas Fayetteville Shale (began 2002)	Population ↑ 2.2% Median HH Income ↑ 6.3% Employment ↑ 2.4%	**Population ↑ 1.3%** **Median HH Income ↑ 2.1%** Employment ↑ 0.5%
10th Congressional Dist, PA Marcellus Shale (began 2006)	Population ↑ 1.4% Median HH Income ↑ 4.0%	Population ↑ 0.1% Median HH Income ↑ 2.5%

[2] It is not clear in the report whether incomes were adjusted for changes in overall price levels (inflation).

But how much did these additional workers earn? In terms of per-capita incomes, all areas experienced a decrease in the average annual growth rate in the second period relative to the first. It appears the U.S. economy did not grow as strongly in the 2000–2006 period than it did in the 1990–2000 period. But surprisingly the average annual growth of per-capita income fell more sharply in the three counties with shale drilling and extraction than was experienced in Pennsylvania. The average annual growth of income decreased by 2.3% in Texas, 4.6% and 4.2% in Arkansas, but only 1.5% in Pennsylvania. Using the differences in differences approach, and again assuming that no other economic or demographic factors capita affect Pennsylvania any differently than Texas or Arkansas, we can only conclude that shale drilling and extraction activities *decreased* per-capita incomes by between 0.8% and 3.1%.

Thus, comparing the data in Texas and Arkansas with that of Pennsylvania crudely suggested that the impact on populations and per-capita incomes is negligible. Economic impact of gas extraction to the Pennsylvania economy could be quite small if (1) well drilling utilizes out-of-state economic resources, and (2) landowners save or spend their lease and royalty payments in other states or countries. The possibility of these two occurrences may not be remote.

But Pennsylvania is a rather poor control area. Regional economic and demographic forces are likely to affect the Pennsylvania economy and the Texas and Arkansas economies in separate ways. If one were to seriously utilize the differences in differences approach to estimate economic impact, then a county or counties not involved with shale gas extraction but within the south-central region of the county would serve as a viable control area. But, based on a misinterpretation of the data, this report adds very little to our understanding of the economic impact of shale gas extraction.

4. Critique of Methods Used to Estimate Economic Impact

Economists are often interested in evaluating the economic impact of an activity such as producing a good or service, completing an investment project, or implementing a public policy measure. A common goal of economic inquiry is whether the activity is economically efficient. An activity is deemed efficient if the value society places on the activity exceeds the value of all economic resources allocated to performing the activity. That is, the activity is deemed efficient if its benefits exceed its costs. Several research tools are available to economists to estimate both benefits and costs of gas extraction.

These reports, on the other hand, estimate economic impact of gas extraction by estimating the effect on gross revenues, jobs created, and tax revenue. The theoretical origins that justify this method of estimating economic impact were developed by John Keynes in the 1930's to explain and understand the Great Depression (Snowdon and Vane, 2005). A Keynesian economy arises wherever economic resources such as labor, capital infrastructure, and natural resources lay idle. The economy is not at full employment—surpluses of labor are evident and factories are operating below capacity. The economic solution to these economic episodes is to increase spending. Keynes called upon the Federal Government to initiate this spending, but the solution works just as well if the spending is initiated by a private industry. Keynesian theory suggests that initial direct spending will increase incomes that will consequently facilitate additional rounds of spending. Economic resources such as labor and capital will be put back to use to satisfy the new needs of consumers, and incomes throughout the economy will increase. It is these economic effects that these two reports attempt to estimate. Keynesian economics guided both government policy makers and many economists for most of the middle decades of the 20th century and receive renewed attention during the fallout from the recent financial crisis of 2008.

The weaknesses of the Keynesian view of the economy were articulated by economists such as Milton Friedman and other neo-classical economists (Carlson and Spencer, 1975). Friedman envisioned a limit for direct spending to increase incomes if economic resources such as labor and physical capital are fully employed. The Friedman economy made its appearance in the late 1960's and 1970's—when high levels of direct spending by consumers, firms and government stripped the economy of its economic resources and the resulting shortages caused prices to rise (inflation). Additional direct spending by the gas industry in such an economy would simply crowd out spending by other industries. The many firms servicing pad development, drilling, road construction, and frac water treatment and removal would be unavailable for other purposes. The economic impact of the shale gas industry on gross expenditures, jobs, and tax revenues would therefore be zero. The economy has simply shifted resources from the production of other goods and services towards the extraction of natural gas. Economic resources necessary to fuel a growing industry would either relocate from other regions of the country or shift from local industries within the region. The IMPAN model used to estimate these economic impacts largely ignores the possibilities of direct spending crowding out other users of the resource. For example, the hotels and restaurants that are at full capacity serving the gas industry are no longer available to tourists and other households. IMPLAN is not equipped to subtract the spending from the crowded out tourists and therefore can overestimate the economic impacts.

Thus, the economic impacts estimated in both reports are only possible in an economy operating below full employment. The recent direct spending from the gas industry during these past few years of recession could have increased incomes as reported, but as the economy recovers from the recent recession the economic impact could dissipate.

Another theoretical weakness of this method of measuring economic impact is the lack of economy-wide logical consistency. If an economist ran an IMPLAN model on every industry, the direct spending of each industry would be multiplied to estimate the effects on the economy. But as every industry claims responsibility for jobs and revenues in other industries that supply the industry, IMPLAN would estimate more economic activity than actually occurs. Undoubtedly there is an industry that could claim responsibility for jobs and revenues within the natural gas industry. The residential construction industry, for example, may claim that much of the spending on gas extraction was induced by the construction of residential homes. In the end, each industry is claiming partial responsibility for the spending of every other industry. But simple logic suggests things will not add up. Therefore, all impact statements based on input–output models such as IMPLAN are likely overstated.

The popularity of using models such as IMPLAN for estimating economic impact lies not upon its theoretical justification but upon its relative ease (inexpense) when compared to cost-benefit analysis described below. Estimating “local jobs created” also speaks the language of elected officials, who are often more interested in short term jobs reports than in the long term benefits that materialize with economic efficiency. The third convenient attribute to the IMPLAN method is the ability to separate economic impact to a specified region or state. This ability once again is helpful to state-wide politicians, who might care for more for the economy of their home state than the economy of neighboring states.

5. Cost-Benefit Analysis

The question most economists and long-term oriented politicians is whether the overall benefits of extracting the gas exceed the costs (Hahn, 2010). Unfortunately neither of these six reports addresses this question. This section outlines what a benefit-cost analysis of gas extraction from the Marcellus shale might look like.

The first and most obvious benefit of extracting natural gas is that natural gas is a source of energy useful for home heating, electricity generation, and to the production process in many industries. The value the economy places on each unit of natural gas is measured hypothetically as the most a household or firm would be willing to pay (WTP) for each unit of gas. Whether the consumer of gas resides within the studied economy or not is not material to the analysis. This maximum WTP can be estimated by extrapolating from market data. We observe quantities falling when prices rise, so the maximum WTP was obviously exceeded by the price for at least some households, utilities, and firms. With sufficient variation in market prices and quantities, economists can estimate the maximum WTP (or "demand") for natural gas as a function of its price and other relevant variables. The literature is full of such research (Al-Sahlawi, 1989). These benefits to consumers of natural gas comprise by far the most sizeable benefit of gas extraction.

Another benefit unique to natural gas production (relative to the production of some other good or service) is the positive spillover effects from using a relatively clean source of energy. If increases in natural gas production reduce the demand for oil and coal, then for any given level of energy consumption, carbon dioxide emissions and other air pollutants such as sulfur and nitrogen decrease. Measuring this benefit is rather tricky, but papers in the economics literature have estimated the value of harm caused from carbon, sulfur, and other air pollutants (Smith and Huang, 1995). These results could be applied to estimate this benefit associated with natural gas extraction.

The costs of natural gas extraction include, perhaps paradoxically, all of the items listed as "benefits" in the six reports discussed above. Natural gas extraction requires labor, capital equipment, pipelines, and raw materials. These economic resources, in a fully employed economy, could have been allocated to other uses. The price paid to secure these resources from these other industries indicates the value of these resources to these other industries (had their value been higher, the market price would have been higher). Thus, the quantity of each economic resource times its market price – in fact the total expenses by the industry as gathered in the surveys – represents the cost of utilizing scarce economic resources to gas extraction.[3]

Another cost of natural gas extraction is the nuisance, noise, and loss of privacy to the owners of the property hosting the drill pads. Because land is privately owned and protected against unlawful trespass by our legal system, gas extractors can only enter land with permission from the property owner. This permission is granted only with sufficient compensation for losses resulting from the nuisance. In other words, the lease agreements and royalty payments paid to landowners serve as credible estimate of the nuisance cost of drilling for gas. This logic requires sufficient competition in the industry—gas extractors must have many property owners to negotiate with and property owners must have many gas extractors to negotiate with.

Third, the extraction of a nonrenewable natural resource such as natural gas creates user costs. Extracting the gas in the present imposes a cost to future generations who face lower stocks of the nonrenewable resource. These user costs are internalized by the gas industry if property rights for natural supplies of shale gas are well defined. If a particular extractor has secured a lease agreement to extract gas from a particular shale field, then the extractor claims ownership of that gas. With property rights secured and protected, the extractor will only extract the gas if the price received today exceeds the price expected tomorrow (after appropriate discounting). If the extraction occurs today, then the extractor has imposed a cost on itself because extracting today reduces the available gas to extract in the future. The tastes and needs of future generations therefore weigh upon the extractors decision to extract today, and user costs are internalized by the extractor. This user cost will cause the market price in the present to rise above the marginal current cost of extraction.

[3] Workers in a fully employed economy also need to be relocated and trained. This latter cost may not appear in the industry's expense reports.

If, on the other hand, rights to extract gas from any particular area are not well defined – perhaps gas migrates with changing subterranean pressures – then any gas left in the ground for future generations could be lost to the owner. The objective of the firm is to extract the gas as quickly as possible before someone else does. The costs to future generations are not considered in a "use it or lose it" environment, and market prices today will fall to the marginal current cost of extraction. In this case the user costs would have to be estimated separately for inclusion in the cost-benefit analysis.

The final cost of gas extraction is the value of all damages done to the natural environment (Weinstein and Clower, 2009). Hydraulic fractioning involves the use of water from local streams. The backflow (frac water) is radioactive and contains high levels of sodium and other elements that are dangerous to wildlife. The natural habitat surrounding well pads, service roads, and pipelines is segmented, which presents difficulties for many species. Add to this the vehicular traffic on roadways and the general nuisance to neighboring households that are not compensated by the industry. All of these costs are external to the market and must be estimated using imperfect but helpful economic research tools such as the hedonic pricing method, the contingent valuation method, or the travel-cost method.

To conclude, economists possess the tools necessary to estimate all benefits and costs associated with shale gas extraction. If the economic value of the gas exceeds the sum of the internalized production costs to industry plus the user costs plus the external costs, then the economic benefits of gas extraction exceed the economic costs. Gas extraction would have a positive *economic impact*, and the magnitude of this impact would depend upon the difference between the benefits and costs. Notice that jobs created, revenues generated, or taxes paid are not part of the analysis.

6. Severance Tax or Pigouvian Tax?

Many of these reports estimate the consequences to the industry and state economy from the imposition of a severance tax on natural gas extraction and perhaps other policy measures. Based on the imperfect econometric model described above (Considine et al., 2009), one result suggests that a severance tax could decrease gas drilling activity by 30%. But both omitted variables and econometric misspecification may bias this result. A second report (CBER, 2008) uses a survey of the industry to estimate drilling would decrease by an average of 13%. But until a better model is specified, we do not know with any confidence how industry will respond to a severance tax. For example, natural gas prices recently decreased by over 50% between the summer of 2008 and the late fall of 2009. These estimates predict a 150% to 300% reduction in well drilling. Yet, actual well drilling over this period in Texas and Pennsylvania did not decrease by any significant magnitude.

Economists generally support the implementation of excise taxes on industries that generate external costs to the environment (Baumol, 1972). The goal is not to transfer wealth from the industry to the state, but to encourage industries to internalize all costs of their production efforts. The optimal "Pigouvian" tax on each unit of gas extracted should be set equal to the marginal external cost that each unit of extracted gas generates. If firms respond to the tax by reducing gas extraction, then the social costs of that gas extraction (the costs to industry plus costs to others) must have exceeded the benefits of that gas extraction. Firms therefore over extract natural gas in the absence of the tax. Once the tax is implemented, the reduction in gas extraction, whether it is 13% or 30%, yields positive benefits to society. A tax set equal to the marginal social cost of extraction will encourage firms to extract the socially optimal quantity of gas. As an added benefit, the revenue generated from the severance tax can facilitate a reduction in income taxes. Many economists argue that income taxes slow economic activity (Bovenberg and Goulder, 1996).

7. Conclusion

This paper reviewed several reports estimating the economic impact from the extraction of natural gas from shale rock formations. The review is necessitated by the need to distinguish consulting reports released under academic institutional affiliation from peer reviewed economic research. Three shortcomings were identified from this peer review. These shortcomings could be corrected by (1) including better assumptions of when and where households spend windfall gains, (2) clarifying the process used to determine where suppliers to the industry and royalty earnings households are located (in state or not), and (3) developing a more appropriate econometric model to estimate well drilling as a function of current price and other relevant variables. Making these changes would likely decrease the size of the economic impacts estimated in these papers, but new estimates would likely be more accurate. Comments made throughout these papers that estimates are "conservative" are for the most part not appropriate and should be ignored. Given the assumptions made in relation to these three shortcomings, the estimates are very likely overstated.

If these reports are not widely read, then any harm done is inconsequential. But if institutional affiliation increases the exposure of these reports, then policy makers and other readers may be misguided by questionable economic estimates. Providing accurate estimates of the economic impact of shale extraction is important to the functioning of the state economy. Households and firms can be expected to base investment decisions on such forecasts, and overstating the economic impacts to persuade government officials could cause other disruptions in the economy if private investment decisions are based on poorly estimated economic impacts.

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Secretary of Energy Advisory Board

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
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Shale Gas Production Subcommittee Second Ninety Day Report

November 18, 2011

U.S. DEPARTMENT OF ENERGY

The SEAB Shale Gas Production Subcommittee Second Ninety Day Report – November 18, 2011

Executive Summary

The Shale Gas Subcommittee of the Secretary of Energy Advisory Board is charged with identifying measures that can be taken to reduce the environmental impact and to help assure the safety of shale gas production. Shale gas has become an important part of the nation's energy mix. It has grown rapidly from almost nothing at the beginning of the century to near 30 percent of natural gas production. Americans deserve assurance that the full economic, environmental and energy security benefits of shale gas development will be realized without sacrificing public health, environmental protection and safety. On August 18, 2011 the Subcommittee presented its initial Ninety-Day Report[1] including twenty recommendations that the Subcommittee believes, if implemented, would assure that the nation's considerable shale gas resources are being developed responsibly, in a way that protects human health and the environment and is most beneficial to the nation. The Secretary of Energy's charge to the Subcommittee is included in Annex A and members of the Subcommittee are given in Annex B.

In this report the Subcommittee focuses on implementation of the twenty recommendations presented in its Ninety-day report. The Executive Summary of these recommendations is presented in Annex C.

The Second Ninety-Day Report

The Subcommittee recommendations in its initial report were presented without indicating priority or how each recommendation might be implemented. Progress in achieving the Subcommittee's objective of continuous improvement in reducing the environmental impact of shale gas production depends upon implementation of the Subcommittee recommendation; hence this final report focuses on implementation. On October 31, 2011, the Subcommittee held a public meeting at DOE headquarters in Washington, D.C., to learn the views of the Department of Interior, the Environmental Protection Agency, and the Department of Energy about progress and barriers to implementation of the Subcommittee recommendations.

The Subcommittee is mindful that state and federal regulators and companies are already deeply involved in environmental management. Implementing the twenty Subcommittee recommendations will require a great deal of effort, and regulators, public officials, and companies need to decide how to allocate scarce human and financial resources to each recommendation, potentially shifting effort from other valuable existing activities. All of the Subcommittee recommendations in its Ninety-Day report involve actions by one or more parties: federal officials, state officials, and public and private sector entities.

Two criteria are important in deciding on the allocation: the importance and ease of implementation. Early success in implementing some recommendations may stimulate greater effort on other recommendations, which require greater time and effort for progress. Decisions about when, how and whether to proceed with our recommendations are the responsibility of the public and private participants in the process – not the Subcommittee. But, the Subcommittee can be helpful at identifying those recommendations that seem particularly important and particularly amendable to early action. Accordingly this report classifies the twenty recommendations into three categories:

(1) Recommendations ready for implementation, primarily by federal agencies;

(2) Recommendations ready for implementation, primarily by states;

(3) Recommendations that require new partnerships and mechanisms for success.

<u>The Subcommittee recognizes that successful implementation of each of its recommendations will require cooperation among and leadership by federal, state and local entities. In its initial report, the Subcommittee called for a process of continuous improvement and said: "This process should involve discussions and other collaborative efforts among companies involved in shale gas production (including service companies), state and federal regulators, and affected communities and public interest groups."</u>

The Subcommittee also believes it has a responsibility to assess and report progress in implementing the recommendations in its initial report. Too often advisory committee recommendations are ignored, not because of disagreement with substance, but because the implementation path is unclear or because of the press of more immediate matters on dedicated individuals who are over extended. The Subcommittee does not wish to see this happen to its recommendation, because it believes citizens expect prompt action. Absent action there will be little credible progress in toward reducing in the environmental impact of shale gas production, placing at risk the future of the enormous potential benefits of this domestic energy resource. At this early stage, it is reasonable to assess if initial, constructive, steps are underway; there is no expectation that any of the recommendations could be completely implemented in the three months since the Subcommittee issued its initial report.

(1) Recommendations for implementation, primarily by federal agencies.

The Subcommittee has identified nine recommendations where federal agencies have primary responsibility and that are ready for implementation; these are presented in Table I.

Recommendation #2 Two existing non-profit organizations – the State Review of Oil and Natural Gas Environmental Regulations (STONGER) and the Ground Water Protection Council (GWPC) are two existing organizations that work to share information to improve the quality of regulatory policy and practice in the states. The budgets for these organizations are small, and merit public support. Previously, federal agencies (DOE and EPA) provided funding for STRONGER and GWPC, but federal funding is currently not provided. To maintain credibility to have an ability to set their own agenda these organizations cannot rely exclusively on funding provided by companies of the regulated industry. The Subcommittee has recommended that $5 million per year would provide the resources to STRONGER and the GWCPC needed to strengthen and broaden its activities as discussed in the Subcommittees previous report, for example, updating hydraulic fracturing guidelines and well construction guidelines, and developing guidelines for water supply, air emissions and cumulative impacts. Additionally, DOE and/or EPA should consider making grants to those states that volunteer to have their regulations and practices peer-reviewed by STRONGER, as an incentive for states to undergo updated reviews and to implement recommended actions.

Table 1. Recommendations ready for immediate implementation		
Rec.#	**Recommendation**	**Comment & Status**
1.	Improve public information about shale gas operations	Federal responsibility to begin planning for public website. Some discussion between DOE and White House offices about possible hosting sites but no firm plan. States should also consider establishing sites.
2.	Improve communication among federal and state regulators and provide federal funding for STRONGER and the Ground Water Protection Council	Federal funding at $5m/y will allow state regulators/NGOs/industry to plan activities. Possible minor DOE FY2012 funding; no multi-year commitment. See discussion below.
3	Measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as practicable.	We encourage EPA to complete its current rule making as it applies to shale gas production quickly, and explicitly include methane, a greenhouse gas, and controls from existing shale gas production sources. Additionally, some states have taken action in this area, and others could do so as well. See discussion below.
4	Enlisting a subset of producers in different basins to design and field a system to collect air emissions data.	Industry initiative in advance of regulation. Several companies have shown interest. Possible start in Marcellus and Eagle Ford. See discussion below.
5	Immediately launching a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of natural gas use.	OSTP has not committed to leading an interagency effort, but the Administration is taking steps to collect additional data, including through the EPA air emissions rulemaking.
6	Encouraging shale-gas production companies and regulators to expand immediately efforts to reduce air emissions using proven technologies and practices.	A general statement of the importance the Subcommittee places on reducing air emissions. Federal funding at $5m/y for state regulators/NGOs/industry will encourage planning. Some states have taken action in this area, and others could do so as well.
11	Launch addition field studies on possible methane migration from shale gas wells to water reservoirs.	No new studies launched; funding required from fed agencies or from states.[2]
14	Disclosure of Fracturing fluid composition	DOI has announced its intent to propose requirement. Industry appears ready to agree to mandatory stricter disclosure. See discussion below.
15	Elimination of diesel use in fracturing fluids	EPA is developing permitting guidance under the UIC program. The Subcommittee reiterates its recommendation that diesel fuel should be eliminated in hydraulic fracturing fluids.
20	R&D needs	OMB/OSTP must define proper limits for unconventional gas R&D and budget levels for DOE, EPA, and USGS. See discussion below.

Funding for the GWPC would allow the association to extend and expand its *Risk Based Data Management System,* which helps states collected and publicly share data associated with their oil and gas regulatory programs – for example, sampling and monitoring programs for surface waters, water wells, sediments and isotropic activity in and around areas of shale gas operations. Likewise, funding could go toward integrating the RBDMS into the national data portal discussed in Recommendation #1. Funding would also allow GWPC to upgrade its fracturing fluid chemical disclosure registry, *Frac Focus*, so that information can be searched, sorted and aggregated by chemical, by well, by company and by geography – as recommended by the Subcommittee in its 90-Day report.

Recommendation #3 On July 28th the U.S. EPA proposed New Source Performance Standards and National Emissions Standards for Hazardous Air Pollutants (NSPS/NESHAPs) for the oil and natural gas sector. The proposed rules, which are currently under comment and review, are scheduled to be finalized by April 3, 2012, represent a critical step forward in reducing emissions of smog-forming pollutants and air toxics. The Subcommittee commends EPA for taking this important step and encourages timely implementation. However, the proposed rules fall short of the recommendations made in the Subcommittee's Ninety-Day Report because the rules do not directly control methane emissions and the NSPS rules as proposed do not cover existing shale gas sources except for fractured or re-fractured existing gas wells.

Additionally, in its Ninety-Day report the Subcommittee recommended that companies be required to measure and disclose air emissions from shale gas sources. Recently, in response to a challenge, the EPA took two final actions that compromise the ability to get accurate emissions data from the oil and gas sector under the Greenhouse Gas Reporting Rule.[3] The Subcommittee reiterates its recommendation that the federal government or state agencies require companies to measure and disclose air emissions from shale gas sources.

Recommendation #4 The Subcommittee is aware that operating companies are considering projects to collect and disclose air emissions data from shale gas production sites. Discussions are underway to define the data to be collected, appropriate instrumentation, and subsequent analysis and disclosure of the data. The Subcommittee welcomes this development and underscores its earlier recommendation for disclosure, including independent technical review of the methodology.

Recommendation #14 The Subcommittee welcomes the announcement of the DOI of its intent to require disclosure of fracturing fluid composition on federal lands. The Subcommittee was pleased to learn from the DOI at its October 31, 2011 public hearing that the agency intends to follow the disclosure recommendations in its Ninety-Day Report that disclosure should include all chemicals, not just those that appear on

Material Safety Data Sheets, and that chemicals should be reported on a well-by-well basis and posted on a publicly available website that includes tools for searching and aggregating data by chemical, by well, by company and by geography. The Subcommittee recognized the need for protection of legitimate trade secrets but believes that the bar for trade secret protection should be high. The Subcommittee believes the DOI disclosure policy should meet the Subcommittee's criteria and that it can serve as a model for the states. The Ground Water Protection Council and the Interstate Oil and Gas Compact Commission have taken an important step in announcing their intent to require disclosure of all chemicals by operators who utilize their voluntary chemical disclosure registry, FracFocus. The Subcommittee welcomes this progress and encourages those organizations to continue their work toward upgrading FracFocus to meet the Subcommittee's recommended disclosure criteria.

Recommendation #20 As set out in its Ninety-day report, the Subcommittee believes there is a legitimate role for the federal government in supporting R&D on shale gas, arguably the country's most important domestic energy resource. To be effective such an R&D program must be pursued for several years, at a relatively modest level. The Subcommittee is aware that discussions have taken place between OMB and the involved agencies, DOI/USGS, DOE, and EPA about funding for unconventional gas R&D. The Subcommittee understands that agreement has been reached that the administration will seek funding for "priority items" for FY2012 in its discussions with Congress, but the "priority items" and the level of this funding is not decided. The Subcommittee welcomes the agencies effort to coordinate their planned out-year research effort for FY2013 and beyond, as described by DOI, DOE, and EPA at its public meeting on October 31, 2011. But, as yet, there has been no agreement with OMB on the scale and composition of a continuing unconventional gas R&D program. Failure to provide adequate funding for R&D would be deleterious and undermine achieving the policy objectives articulated by the President.

Note: after the Subcommittee completed its deliberations the Office of Management and Budget sent a letter setting forth the efforts underway to find funding for the Subcommittee recommendations; **see Annex D**. While the letter does not settle the matter, it is an important and welcome, positive step.

(2) Recommendations ready for implementation, primarily by states.

The Subcommittee has identified four recommendations in this category; all address water quality related issues.

Table 2. Recommendations requiring cooperation between regulators and industry

Rec.#	Recommendation	Comment & Status
8	Measure and publicly report the composition of water stocks and flow throughout the fracturing and cleanup process.	Awaits EPA's study underway on the Impacts of hydraulic fracturing on drinking water resources. See discussion below. States should also determine a way forward to measure and record data from flow back operations as many issues will be local issues.
9	Manifest all transfers of water among different locations	
10	Adopt best practices in well development and construction, especially casing, cementing, and pressure management	Widely recognized as a key practice by companies and regulators but no indication of a special initiative on field measurement and reporting.
12	Adopt requirements for background water quality measurements	The value of background measurements is recognized. Jurisdiction for access to private wells differs widely

Recommendation #8 and 9 EPA has a number of regulatory actions in process. On October 20, 2011 EPA announced a schedule setting waste water discharge standards that will affect some shale gas production activities.[4] Further water quality regulatory developments will benefit from the results of EPA's study on the impact of hydraulic fracturing on drinking water that will not be complete until 2014 and will likely initiate significant negotiation between EPA and state regulators on the scope and responsibility for water regulations. The Subcommittee observes that there will be a tremendous amount of activity in the field before EPA completes its study (and any potential regulatory actions that flow from it) and urges the EPA to take action as appropriate during the course of its process.

Recommendation #12 In its initial report, the Subcommittee called for background water measurements at wells surrounding planned production sites to establish an objective benchmark to assess potential damage to water resources. All stakeholders agree that such measurements can be helpful in establishing facts and verifying disputed contamination claims. The lack of a clear pattern of state, local, and federal authority for access to private water wells to make such measurements is an impediment to policy development.

(3) Recommendations that require new partnerships or mechanisms for success

The following recommendations require development of new partnerships or mechanisms and hence the implementation challenge can be quite significant. These recommendations do, however, signal significant concerns shared by members of the Subcommittee that are noted in Table 3. The challenge is to devise new mechanisms for addressing these significant environmental problems.

Table 3. Recommendations that require new mechanisms for success

Rec.#	Recommendation	Comment & Status
7	Protection of water quality through a systems approach.	At present neither EPA or the states are engaged in developing a systems/lifecycle approach to water management.
13	Agencies should review field experience and modernize rules and enforcement practices to ensure protection of drinking and surface waters.	Reflects Subcommittee unease that the present arrangement of shared federal and state responsibility for cradle-to-grave water quality is not working smoothly or as well as it should.
16	Managing short-term and cumulative impacts on communities, land use, wildlife, and ecologies.	No new studies launched; funding required from federal agencies or from states. See discussion below.
17	Organizing for best practice.	Industry intends to establish 'centers of excellence' regionally, that involve public interest groups, state and local regulatory and local colleges and universities.
18	Air	
19	Water	

Recommendation #16 Shale gas production brings both benefits and cost of economic development to a community, often rapidly and in a region that it is unfamiliar with oil and gas operations. Short and long term community impact range from traffic, noise, land use, disruption of wildlife and habitat, with little or no allowance for planning or effective mechanisms to bring companies, regulators, and citizens to deliberate about how best to deal with near term and cumulative impacts. The Subcommittee does not believe that these issues will solve themselves or be solved by prescriptive regulation or in the courts. State and local governments should take the lead in experimenting with different mechanisms for engaging these issues in a constructive way, seeking to be beyond discussion to practical mitigation. Successful models should be disseminated.

The U.S. Department of Interior, however, is somewhat unique in having tools at its disposal that could be used to address cumulative and community impacts. For example, Master Leasing and Development Plans, a relatively new tool, might help improve planning for production on federal lands through requirements for phased leasing and development, multi-well pad drilling, limitations on surface disturbance, centralization of infrastructure, land and roadway reclamation, etc.

Recommendation 17, 18 & 19 Industry has always been interested in best practices. The Subcommittee has called for industry to increase their best practices process for field engineering and environmental control activities by adopting the objective of continuous improvement, validated by measurement and disclosure of key operating metrics.[5] Leadership for this initiative lies with industry but also involves regulators and public interest groups. Best practices involves the entire range of shale gas operations including: (a) well design and siting, (b) drilling and well completion, including importantly casing and cementing, (c) hydraulic fracturing, (d) surface operations, (e) collection and distribution of gas and land liquids, (f) well abandonment and sealing, and (g) emergency response. Developing reliable metrics for best practices is a major task and must take into account regional differences of geology and regulatory practice. A properly trained work force is an important element in achieving best practice. Thus, organizing for best practice should include better mechanisms for training of oil field workers. Such training should utilize local community college and vocational education resources.

Industry is taking a regional approach to best practice, building on local organizations, such as the Marcellus Shale Coalition. Shale companies understand the importance of involving non-industry stakeholders in their efforts and are beginning to take initiatives that engage the public in a meaningful way. Industry is showing increased interest in engineering practice as indicated by the recent workshop on hydraulic fracturing sponsored by the American Petroleum Institute on October 4 and 5, 2011 in Pittsburg PA.[6] The Subcommittee urges leading companies to adopt a more visible commitment to using quantitative measures as a means of achieving best practice and demonstrating to the public that there is continuous improvement in reducing the environmental impact of shale gas production.

Concluding remarks

The Subcommittee was gratified with the generally favorable, but not universally favorable, response to its initial report. In particular there was overwhelming agreement on two points: (1) If the country is to enjoy the economic and other benefits of shale gas production over the coming years disciplined attention must be devoted to reducing the environmental impact that accompanies this development, and (2) a prudent balance between development and environmental protection is best struck by establishing a strong foundation of regulation and enforcement, and adopting a policy and practice that measures, discloses, and continuously improves shale gas operations.

The Subcommittee believes that if action is not taken to reduce the environmental impact accompanying the very considerable expansion of shale gas production expected across the country – perhaps as many as 100,000 wells over the next several decades – there is a real risk of serious environmental consequences causing a loss of public confidence that could delay or stop this activity. Thus, the Subcommittee interest in assessing and reporting on the progress that is being made on implementing its recommendations or, or some sensible variations of the recommendations.

The Subcommittee has the impression that its initial report stimulated interest in taking action to reduce the environmental impact of shale gas production by the administration, state governments, industry, and public interest groups. However, the progress to date is less than the Subcommittee hoped and it is not clear how to catalyze action at a time when everyone's attention is focused on economic issues, the press of daily business, and an upcoming election. The Subcommittee cautions that whether its approach is followed or not, some concerted and sustained action is needed to avoid excessive environmental impacts of shale gas production and the consequent risk of public opposition to its continuation and expansion.

ANNEX A – CHARGE TO THE SUBCOMMITTEE

From: Secretary Chu

To: William J. Perry, Chairman, Secretary's Energy Advisory Board (SEAB)

On March 30, 2011, President Obama announced a plan for U.S. energy security, in which he instructed me to work with other agencies, the natural gas industry, states, and environmental experts to improve the safety of shale gas development. The President also issued the Blueprint for a Secure Energy Future ("Energy Blueprint"), which included the following charge:

> **"Setting the Bar for Safety and Responsibility:** To provide recommendations from a range of independent experts, the Secretary of Energy, in consultation with the EPA Administrator and Secretary of Interior, should task the Secretary of Energy Advisory Board (SEAB) with establishing a subcommittee to examine fracking issues. The subcommittee will be supported by DOE, EPA and DOI, and its membership will extend beyond SEAB members to include leaders from industry, the environmental community, and states. The subcommittee will work to identify, within 90 days, any immediate steps that can be taken to improve the safety and environmental performance of fracking and to develop, within six months, consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment." *Energy Blueprint (page 13).*

The President has charged us with a complex and urgent responsibility. I have asked SEAB and the Natural Gas Subcommittee, specifically, to begin work on this assignment immediately and to give it the highest priority.

This memorandum defines the task before the Subcommittee and the process to be used.

Membership:

In January of 2011, the SEAB created a Natural Gas Subcommittee to evaluate what role natural gas might play in the clean energy economy of the future. Members of the Subcommittee include John Deutch (chair), Susan Tierney, and Dan Yergin. Following consultation with the Environmental Protection Agency and the Department of the Interior, I have appointed the following additional members to the Subcommittee: Stephen Holditch, Fred Krupp, Kathleen McGinty, and Mark Zoback.

The varied backgrounds of these members satisfies the President's charge to include individuals with industry, environmental community, and state expertise. To facilitate an expeditious start, the Subcommittee will consist of this small group, but additional members may be added as appropriate.

Consultation with other Agencies:

The President has instructed DOE to work in consultation with EPA and DOI, and has instructed all three agencies to provide support and expertise to the Subcommittee. Both agencies have independent regulatory authority over certain aspects of natural gas production, and considerable expertise that can inform the Subcommittee's work.

- The Secretary and Department staff will manage an interagency working group to be available to consult and provide information upon request of the Subcommittee.
- The Subcommittee will ensure that opportunities are available for EPA and DOI to present information to the Subcommittee.
- The Subcommittee should identify and request any resources or expertise that lies within the agencies that is needed to support its work.
- The Subcommittee's work should at all times remain independent and based on sound science and other expertise held from members of the Subcommittee.
- The Subcommittee's deliberations will involve only the members of the Subcommittee.
- The Subcommittee will present its final report/recommendations to the full SEAB Committee.

Public input:

In arriving at its recommendations, the Subcommittee will seek timely expert and other advice from industry, state and federal regulators, environmental groups, and other stakeholders.

- To assist the Subcommittee, DOE's Office of Fossil Energy will create a website to describe the initiative and to solicit public input on the subject.
- The Subcommittee will meet with representatives from state and federal regulatory agencies to receive expert information on subjects as the Subcommittee deems necessary.
- The Subcommittee or the DOE (in conjunction with the other agencies) may hold one or more public meetings when appropriate to gather input on the subject.

Scope of work of the Subcommittee:

The Subcommittee will provide the SEAB with recommendations as to actions that can be taken to improve the safety and environmental performance of shale gas extraction processes, and other steps to ensure protection of public health and safety, on topics such as:

- well design, siting, construction and completion;
- controls for field scale development;
- operational approaches related to drilling and hydraulic fracturing;
- risk management approaches;
- well sealing and closure;
- surface operations;
- waste water reuse and disposal, water quality impacts, and storm water runoff;
- protocols for transparent public disclosure of hydraulic fracturing chemicals and other information of interest to local communities;
- optimum environmentally sound composition of hydraulic fracturing chemicals, reduced water consumption, reduced waste generation, and lower greenhouse gas emissions;

- emergency management and response systems;
- metrics for performance assessment; and
- mechanisms to assess performance relating to safety, public health and the environment.

The Subcommittee should identify, at a high level, the best practices and additional steps that could enhance companies' safety and environmental performance with respect to a variety of aspects of natural gas extraction. Such steps may include, but not be limited to principles to assure best practices by the industry, including companies' adherence to these best practices. Additionally, the Subcommittee may identify high-priority research and technological issues to support prudent shale gas development.

Delivery of Recommendations and Advice:

- Within 90 days of its first meeting, the Subcommittee will report to SEAB on the "immediate steps that can be taken to improve the safety and environmental performance of fracking."
- Within 180 days of its first meeting, the Subcommittee will report to SEAB "consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment."
- At each stage, the Subcommittee will report its findings to the full Committee and the SEAB will review the findings.
- The Secretary will consult with the Administrator of EPA and the Secretary of the Interior, regarding the recommendations from SEAB.

Other:

- The Department will provide staff support to the Subcommittee for the purposes of meeting the requirements of the Subcommittee charge. The Department will also engage the services of other agency Federal employees or contractors to provide staff services to the Subcommittee, as it may request.
- DOE has identified $700k from the Office of Fossil Energy to fund this effort, which will support relevant studies or assessments, report writing, and other costs related to the Subcommittee's process.
- The Subcommittee will avoid activity that creates or gives the impression of giving undue influence or financial advantage or disadvantage for particular companies involved in shale gas exploration and development.
- The President's request specifically recognizes the unique technical expertise and scientific role of the Department and the SEAB. As an agency not engaged in regulating this activity, DOE is expected to provide a sound, highly credible evaluation of the best practices and best ideas for employing these practices safely that can be made available to companies and relevant regulators for appropriate action. Our task does not include making decisions about regulatory policy.

ANNEX B – MEMBERS OF THE SUBCOMMITTEE

John Deutch, Institute Professor at MIT (Chair) **-** John Deutch served as Director of Energy Research, Acting Assistant Secretary for Energy Technology and Under Secretary of Energy for the U.S. Department of Energy in the Carter Administration and Undersecretary of Acquisition & Technology, Deputy Secretary of Defense and Director of Central Intelligence during the first Clinton Administration. Dr. Deutch also currently serves on the Board of Directors of Raytheon and Cheniere Energy and is a past director of Citigroup, Cummins Engine Company and Schlumberger. A chemist who has published more than 140 technical papers in physical chemistry, he has been a member of the MIT faculty since 1970, and has served as Chairman of the Department of Chemistry, Dean of Science and Provost. He is a member of the Secretary of Energy Advisory Board.

Stephen Holditch, Head of the Department of Petroleum Engineering at Texas A&M University and has been on the faculty since 1976 - Stephen Holditch, who is a member of the National Academy of Engineering, serves on the Boards of Directors of Triangle Petroleum Corporation and Matador Resources Corporation. In 1977, Dr. Holditch founded S.A. Holditch & Associates, a petroleum engineering consulting firm that specialized in the analysis of unconventional gas reservoirs. Dr. Holditch was the 2002 President of the Society of Petroleum Engineers. He was the Editor of an SPE Monograph on hydraulic fracturing treatments, and he has taught short courses for 30 years on the design of hydraulic fracturing treatments and the analyses of unconventional gas reservoirs. Dr. Holditch worked for Shell Oil Company prior to joining the faculty at Texas A&M University.

Fred Krupp, President, Environmental Defense Fund **-** Fred Krupp has overseen the growth of EDF into a recognized worldwide leader in the environmental movement. Krupp is widely acknowledged as the foremost champion of harnessing market forces for environmental ends. He also helped launch a corporate coalition, the U.S. Climate Action Partnership, whose Fortune 500 members - Alcoa, GE, DuPont and dozens more - have called for strict limits on global warming pollution. Mr. Krupp is coauthor, with Miriam Horn, of New York Times Best Seller, *Earth: The Sequel*. Educated at Yale and the University of Michigan Law School, Krupp was among 16 people named as America's Best Leaders by U.S. News and World Report in 2007.

Kathleen McGinty, Kathleen McGinty is a respected environmental leader, having served as President Clinton's Chair of the White House Council on Environmental Quality and Legislative Assistant and Environment Advisor to then-Senator Al Gore. More recently, she served as Secretary of the Pennsylvania Department of Environmental Protection. Ms. McGinty also has a strong background in energy. She is Senior Vice President of Weston Solutions where she leads the company's clean energy development business. She also is an Operating Partner at Element Partners, an investor in efficiency and renewables. Previously, Ms. McGinty was Chair of the Pennsylvania Energy Development Authority, and currently she is a Director at NRG Energy and Iberdrola USA.

Susan Tierney, Managing Principal, Analysis Group **-** Susan Tierney is a consultant on energy and environmental issues to public agencies, energy companies, environmental organizations, energy consumers, and tribes. She chairs the Board of the Energy Foundation, and serves on the Boards of Directors of the World Resources Institute, the Clean Air Task Force, among others. She recently, co-chaired the National Commission on Energy Policy, and chairs the Policy Subgroup of the National Petroleum Council's study of North American natural gas and oil resources. Dr. Tierney served as Assistant Secretary for Policy at the U.S. Department of Energy during the Clinton Administration. In Massachusetts, she served as Secretary of Environmental Affairs, Chair of the Board of the Massachusetts Water Resources Agency, Commissioner of the Massachusetts Department of Public Utilities and executive director of the Massachusetts Energy Facilities Siting Council.

Daniel Yergin, Chairman, IHS Cambridge Energy Research Associates **-** Daniel Yergin is the co-founder and chairman of IHS Cambridge Energy Research Associates. He is a member of the U.S. Secretary of Energy Advisory Board, a board member of the Board of the United States Energy Association and a member of the U.S. National Petroleum Council. He was vice chair of the 2007 National Petroleum Council study, *Hard Truths* and is vice chair of the new National Petroleum Council study of North American natural gas and oil resources. He chaired the U.S. Department of Energy's Task Force on Strategic Energy Research and Development. Dr. Yergin currently chairs the Energy Security Roundtable at the Brookings Institution, where he is a trustee, and is member of the advisory board of the MIT Energy Initiative. Dr. Yergin is also CNBC's Global Energy Expert. He is the author of the Pulitzer Prize-winning book, *The Prize: The Epic Quest for Oil, Money and Power.* His new book – *The Quest: Energy, Security, and the Remaking of the Modern World* – will be published in September 2011..

Mark Zoback, Professor of Geophysics, Stanford University - Mark Zoback is the Benjamin M. Page Professor of Geophysics at Stanford University. He is the author of a textbook, *Reservoir Geomechanics*, and author or co-author of over 300 technical research papers. He was co-principal investigator of the San Andreas Fault Observatory at Depth project (SAFOD) and has been serving on a National Academy of Engineering committee investigating the Deepwater Horizon accident. He was the chairman and co-founder of GeoMechanics International and serves as a senior adviser to Baker Hughes, Inc. Prior to joining Stanford University, he served as chief of the Tectonophysics Branch of the U.S. Geological Survey Earthquake Hazards Reduction Program.

Annex C – Subcommittee Recommendations

A list of the Subcommittee's findings and recommendations follows.

1. Improve public information about shale gas operations: Create a portal for access to a wide range of public information on shale gas development, to include current data available from state and federal regulatory agencies. The portal should be open to the public for use to study and analyze shale gas operations and results.

2. Improve communication among state and federal regulators: Provide continuing annual support to STRONGER (the State Review of Oil and Natural Gas Environmental Regulation) and to the Ground Water Protection Council for expansion of the *Risk Based Data Management System* and similar projects that can be extended to all phases of shale gas development.

3. Improve air quality: Measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as practicable. The Subcommittee supports adoption of rigorous standards for new and existing sources of methane, air toxics, ozone precursors and other air pollutants from shale gas operations. The Subcommittee recommends:

    4. Enlisting a subset of producers in different basins to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data from shale gas operations and make these data publically available;

    5. Immediately launching a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of shale gas operations throughout the lifecycle of natural gas use in comparison to other fuels; and

    6. Encouraging shale-gas production companies and regulators to expand immediately efforts to reduce air emissions using proven technologies and practices.

7. Protection of water quality: The Subcommittee urges adoption of a systems approach to water management based on consistent measurement and public disclosure of the flow and composition of water at every stage of the shale gas production process. The Subcommittee recommends the following actions by shale gas companies and regulators – to the extent that such actions have not already been undertaken by particular companies and regulatory agencies:

    8. Measure and publicly report the composition of water stocks and flow throughout the fracturing and clean-up process.

    9. Manifest all transfers of water among different locations.

    10. Adopt best practices in well development and construction, especially casing, cementing, and pressure management. Pressure testing of cemented casing and state-of-the-art cement bond logs should be used to confirm formation isolation. Microseismic surveys should be carried out to assure that

hydraulic fracture growth is limited to the gas producing formations. Regulations and inspections are needed to confirm that operators have taken prompt action to repair defective cementing jobs. The regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing.

11. Additional field studies on possible methane leakage from shale gas wells to water reservoirs.

12. Adopt requirements for background water quality measurements (e.g., existing methane levels in nearby water wells prior to drilling for gas) and report in advance of shale gas production activity.

13. Agencies should review field experience and modernize rules and enforcement practices to ensure protection of drinking and surface waters.

14. Disclosure of fracturing fluid composition: The Subcommittee shares the prevailing view that the risk of fracturing fluid leakage into drinking water sources through fractures made in deep shale reservoirs is remote. Nevertheless the Subcommittee believes there is no economic or technical reason to prevent public disclosure of all chemicals in fracturing fluids, with an exception for genuinely proprietary information. While companies and regulators are moving in this direction, progress needs to be accelerated in light of public concern.

15. Reduction in the use of diesel fuel: The Subcommittee believes there is no technical or economic reason to use diesel in shale gas production and recommends reducing the use of diesel engines for surface power in favor of natural gas engines or electricity where available.

16. Managing short-term and cumulative impacts on communities, land use, wildlife, and ecologies. Each relevant jurisdiction should pay greater attention to the combination of impacts from multiple drilling, production and delivery activities (e.g., impacts on air quality, traffic on roads, noise, visual pollution), and make efforts to plan for shale development impacts on a regional scale. Possible mechanisms include:

(1) Use of multi-well drilling pads to minimize transport traffic and need for new road construction.

(2) Evaluation of water use at the scale of affected watersheds.

(3) Formal notification by regulated entities of anticipated environmental and community impacts.

(4) Preservation of unique and/or sensitive areas as off-limits to drilling and support infrastructure as determined through an appropriate science-based process.

(5) Undertaking science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.

(6) Establishment of effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.

The process for addressing these issues must afford opportunities for affected communities to participate and respect for the rights of surface and mineral rights owners.

17. Organizing for best practice: The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice, defined as improvements in techniques and methods that rely on measurement and field experience, is needed to improve operational and environmental outcomes. The Subcommittee favors a national approach including regional mechanisms that recognize differences in geology, land use, water resources, and regulation. The Subcommittee is aware that several different models for such efforts are under discussion and the Subcommittee will monitor progress during its next ninety days. The Subcommittee has identified several activities that deserve priority attention for developing best practices:

    18. Air: (a) Reduction of pollutants and methane emissions from all shale gas production/delivery activity. (b) Establishment of an emission measurement and reporting system at various points in the production chain.

    19. Water: (a) Well completion – casing and cementing including use of cement bond and other completion logging tools. (b) Minimizing water use and limiting vertical fracture growth.

20. Research and Development needs. The public should expect significant technical advances associated with shale gas production that will significantly improve the efficiency of shale gas production and that will reduce environmental impact. The move from single well to multiple-well pad drilling is one clear example. Given the economic incentive for technical advances, much of the R&D will be performed by the oil and gas industry. Nevertheless the federal government has a role especially in basic R&D, environment protection, and safety. The current level of federal support for unconventional gas R&D is small, and the Subcommittee recommends that the Administration and the Congress set an appropriate mission for R&D and level funding.

Annex D Letter from the Office of Management and Budget

EXECUTIVE OFFICE OF THE PRESIDENT
OFFICE OF MANAGEMENT AND BUDGET
WASHINGTON, D.C. 20503

THE DIRECTOR

November 8, 2011

Dr. John Deutch
Chairman
Secretary of Energy Advisory Board on Natural Gas
Washington, DC 20585

Dear John:

Thank you for your letter on Tuesday, November 1 about the Subcommittee of the Secretary of Energy Advisory Board on Natural Gas (SEAB). I am sorry that I could not attend the SEAB meeting earlier this week. Your work on this issue has been very helpful and it is a high priority of the Administration.

As you are aware, the Office of Management and Budget (OMB) is running an interagency working group to coordinate the research budget proposals on hydraulic fracturing and has received some preliminary suggestions from the agencies for FY 2013 activities. Over the course of the next few weeks, the interagency budget working group will review agencies' research proposals taking into consideration core competencies, which I understand was discussed with you on Monday, October 31. We will be looking carefully at the research and development (R&D) recommendations of the SEAB report as we put together the President's FY 2013 Budget.

As you know, all discretionary funding is capped in FY 2012 and FY 2013. Hydraulic fracturing R&D is a priority that we are seeking to fund as we make tough choices within these constraints. As your report acknowledges, the industry has a strong incentive to fund and carry out production-related R&D. To the degree that environmental constraints could impede continued growth, industry also has an interest in R&D to improve environmental performance and safety. Thus, finding the correct balance between public and private investment, within the broader Federal budget constraints is challenging, but important. As part of the R&D budget review, we are identifying existing programs across the government to avoid redundancies and to optimize budgetary resources. As a general matter, OMB does not announce budget decisions prior to the full presentation to the Congress in February of each year.

I am concerned there has been some confusion around OMB's position on funding this research. The Administration has opposed subsidies for conventional fossil energy exploration and production, just as the Bush Administration did. But hydraulic fracturing R&D that adheres to the framework set forth in the SEAB 90-day interim report – for air, water, induced seismicity or other public information needed to set appropriate regulatory boundaries – we strongly support, and we agree that the Environmental Protection Agency, Department of the Interior, and Department of Energy all have roles to play. However, we need to carefully articulate those roles and structure the President's Budget to most efficiently deliver the R&D funding needed to address environmental and safety concerns.

The SEAB 90-day interim report supports the existing Ultradeepwater and Unconventional Natural Gas and Other Petroleum Research Program (Sec. 999) which is funded through mandatory appropriations authorized by the Energy Policy Act of 2005. On this point, we disagree. Mandatory R&D funding from Sec. 999 is too inflexible a mechanism to adequately address environmental and safety concerns in the dynamic and rapidly evolving hydraulic fracturing space, and the President's Budgets have proposed eliminating this mandatory R&D program. Absent Congressional action to repeal Sec. 999, the Administration has sought to refocus this funding to support R&D with significant potential public benefits, including activities consistent with the SEAB recommendations.

Thank you again for reaching out to me on this important issue. Please do not assume that because we are busy, that this issue is not important to the Administration, and feel free to be in touch moving forward.

Hope all is well with you and would look forward to catching up.

Best regards,

Jacob J. Lew

Massachusetts Institute of Technology
77 Massachusetts Avenue
Building 6-215
Cambridge, Massachusetts 02139

John Deutch Institute Professor
Department of Chemistry
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To: Jack Lew, Director Office of Management and Budget

Dear Jack, November 1, 2011

In March, President Obama directed Steve Chu to establish a Subcommittee of the Secretary of Energy Advisory Board on Hydraulic Fracturing tasked to identify steps that should be taken to reduce the environmental impact of shale gas production. I am the chair of this Subcommittee, which released its initial report on August 18, 2011.

One of the Subcommittee's twenty recommendations called on the administration to adopt a unconventional gas R&D program to perform R&D that merits public funding such as environmental studies on methane leakage, assessing the relative greenhouse gas foot print of natural gas production, seismicity, inventing new techniques for real time monitoring and control of hydraulic fluid injection, and development of environmentally friendly stimulation fluids. The Subcommittee did not ask for "new" money, or suggest a particular level of funding, or how responsibilities should be distributed between the DOE, EPA, and the USGS.

On October 5, 2011, I wrote to you requesting that you or a designated representative come and speak with the Subcommittee (in open or closed session) about this matter. You designated Sally Ericsson, Associate Director for Natural Resources, who I understand participated in an interagency meeting on this subject and agreed to attend the Subcommittee's October 31 meeting. Unfortunately, Ms Ericsson had to cancel her attendance, inevitably leaving the Subcommittee, as it prepares its second and final report, with the impression that the administration has not yet been able to formulate a position on the level of distribution of federal support for unconventional gas R&D, arguably the most important near term domestic energy supply option for the country. The Subcommittee did learn that the administration will seek funds for "priority" items for FY2012 in its discussions with Congress and that EPA, DOE, and DOI are coordinating their research plans, but evidently an effective R&D program requires consistent multi-year funding.

I know that you are totally consumed by the budget deficit and countless other matters. Nevertheless, I urge you to devote a few minutes to resolving the issue of federal support for R&D on unconventional gas. President Obama in his *Blue Print for Secure Energy Future* recognized that realizing the enormous economic benefits of shale case requires improving the environmental performance of shale gas production and the *Blue Print* explicitly identified a role for federally sponsored research. It will be a shame if the administration does not take the initial steps necessary to establish a modest, but steady R&D effort by the participating agencies.

Sincerely

John Deutch

John Deutch

Cc: Steven Chu,
Heather Zichal,
Michael Froman

ENDNOTES

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1 The Subcommittee report is available at: http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf

2 Duke University has launched a follow-on study effort to its initial methane migration study. NETL, in cooperation with other federal agencies and with PA state agencies, Penn State, and major producers is launching a study limited to two wells. More needs to be done by federal agencies.

3 First, EPA has finalized a deferral that will prevent the agency from collecting inputs to emissions equations data until 2015 for Subpart W sources. These inputs are critical to verify emissions information calculated using emission equations. Second, EPA has finalized a rule allowing more widespread use of Best Available Monitoring Methods ("BAMM") in 2011 and beyond. This action allows reporters to use more relaxed, non-standard methods when monitoring under Subpart W.
See: Change to the Reporting Date for Certain Data Elements Required Under the Mandatory Reporting of Greenhouse Gases Rule, 76 Fed. Reg. 53,057 (Aug. 25, 2011); and Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems: Revisions to Best Available Monitoring Method Provisions, 76 Fed. Reg. 59,533 (Sept. 27, 2011).

4 The EPA announcement of the schedule to Develop Natural Gas Wastewater Standards can be found on the EPA home web site: http://www.epa.gov/newsroom/. It states:

> **Shale Gas Standards:**Currently, wastewater associated with shale gas extraction is prohibited from being directly discharged to waterways and other waters of the U.S. While some of the wastewater from shale gas extraction is reused or re-injected, a significant amount still requires disposal. As a result, some shale gas wastewater is transported to treatment plants, many of which are not properly equipped to treat this type of wastewater. EPA will consider standards based on demonstrated, economically achievable technologies, for shale gas wastewater that must be met before going to a treatment facility.

5 Since the release of the Subcommittee's Ninety-Day Report, the National Petroleum Council issued its "Prudent Development" report on September 15, 2011, with its recommendation that:

> "Natural gas and oil companies should establish regionally focused council(s) of excellence in effective environmental, health, and safety practices. These councils should be forums in which companies could identify and disseminate effective environmental, health, and safety practices and technologies that are appropriate to the particular region. These may include operational risk management approaches, better environmental management techniques, and methods for measuring environmental performance. The governance structures, participation processes, and transparency should be designed to: promote engagement of industry and other interested parties; and enhance the credibility of a council's products and the likelihood they can be relied upon by regulators at the state and federal level."

NPC, "Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources," Executive Summary Section II.A.1.

6 See: http://www.energyfromshale.org/commitment-excellence-hydraulic-fracturing-workshop

RECEIVED
By Docket Room at 4:08 pm, Dec 17, 2012

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

IN THE MATTER OF	)	
	)	**FE DOCKET NO. 12-100-LNG**
Southern LNG Company, L.L.C.	)	
	)	
	)	

SIERRA CLUB'S MOTION TO INTERVENE, PROTEST, AND COMMENTS

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Table of Contents

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

IN THE MATTER OF	)	
	)	**FE DOCKET NO. 12-100-LNG**
Southern LNG Company, L.L.C.	)	
	)	
	)	

SIERRA CLUB'S MOTION TO INTERVENE, PROTEST, AND COMMENTS

Southern LNG Company, L.L.C. requests authorization to export approximately 0.5 billion cubic feet per day (bcf/d) of natural gas as liquefied natural gas (LNG) from its Elba Island Terminal, located outside Savannah in Chatham County, Georgia. This proposal cannot move forward without extensive environmental and economic analyses that Southern LNG has not provided to the Department of Energy Office of Fossil Energy (DOE/FE). In any event, the available evidence demonstrates that this proposal is inconsistent with the public interest.

In particular, Southern LNG concedes that the proposal would increase natural gas production in the United States. *See, e.g.*, App. at 27 ("[E]xports of domestic LNG will provide an additional market for U.S. production, thereby encouraging exploration, development and production."). DOE/FE cannot authorize exports without fairly weighing significant environmental and economic impacts of this production. *See Udall v. Federal Power Comm'n*, 387 U.S. 428, 450 (1967). Exports will also harm the public interest by increasing domestic gas prices and likely increasing global greenhouse gas emissions. Further, although Southern LNG asserts that the project will benefit Chatham County, the company improperly downplays the project's local environmental impacts.

Because Sierra Club's members have a direct interest in ensuring that domestic natural gas production is conducted safely, and that any exports do not adversely affect domestic consumers, the Club moves to intervene in this proceeding and protests Southern LNG's application.

I. Sierra Club Should be Granted Intervention

Sierra Club members live and work throughout the area that will be affected by the Southern LNG export plan, including in the regions adjacent to the proposed facility and any associated infrastructure. Sierra Club members also live in the domestic gas fields that will likely see increased production as a result of the proposed exports. Sierra Club members everywhere will also be affected by the increased gas prices that would result from completion of proposed LNG export facilities like Southern LNG's. As of December 2012, Sierra Club had 8,966 members in Georgia and 590,264 members overall.[1]

To protect our members' interests, Sierra Club moves to intervene in this proceeding, pursuant to 10 C.F.R. § 590.303. Consistent with that rule, Sierra Club states that its rights and interests in this matter include, but are not limited to, the following:

- The environmental consequences of any gas exports from the Southern LNG facility, including emissions and other pollution associated with the gasification and liquefaction processes, environmental damage associated with construction and operation of the facility and associated infrastructure, environmental impacts caused by shipping traffic, and the emissions associated with all phases of the process from production to combustion.
- The environmental and economic consequences of any expansion or change in natural gas production, especially in shale gas plays, as a result of increased gas exports. Members living in these regions will be affected by the damage to air, land, and water resources caused by the increasing development of these plays, and the public health risks caused by these harms.
- The economic impacts of any gas exports from the Southern LNG facility, whether individually or in concert with exports from other such facilities, including the consequences of price changes upon members' finances, consumer behavior generally, and industrial and electrical generating facilities whose fuel choices may be affected by price changes. Sierra Club, in particular, works to reduce U.S. and global dependence on fossil fuels, including coal, gas, and oil, and to promote clean energy and efficiency in order to protect public health and the environment. To the extent changes in gas prices increase the use and production of coal and oil, Sierra Club's interests in this proceeding are directly implicated.
- The public disclosure, in National Environmental Protection Act and other documents, of all environmental, cultural, social, and economic consequences of Southern LNG's proposal, and of all alternatives to that proposal.

In short, Sierra Club's members have vital economic, aesthetic, spiritual, personal, and professional interests in the project.

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[1] Attached Declaration of Yolanda Andersen at ¶ 7, attached as Exhibit 1.

The Club has demonstrated the vitality of these interests in many ways. Sierra Club runs national advocacy and organizing campaigns dedicated to reducing American dependence on fossil fuels, including natural gas, and to protecting public health. These campaigns, including its Beyond Coal campaign and its Beyond Natural Gas campaign, are dedicated towards promoting a swift transition away from fossil fuels and to reducing the impacts of any remaining natural gas extraction.

Thus, although 10 C.F.R. § 590.303 states no particular standard for intervention, Sierra Club has interests in this proceeding that would be sufficient to support intervention on any standard. This motion to intervene must be granted.[2]

II. Service

Pursuant to 10 C.F.R. § 590.303, Sierra Club identifies the following persons for service of correspondence and communications regarding this application. The Club respectfully requests that DOE/FE add all three of the individuals listed to the service list, notwithstanding 10 C.F.R. § 590.303(d), which limits service to two individuals.

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[2] If any other party opposes this motion, we respectfully request leave to reply. *Cf.* 10 C.F.R. §§ 590.302, 590.310 (allowing for procedural motions and briefing in these cases).

III. Sierra Club Protests this Application Because It Is Not In the Public Interest and Is Not Supported by Adequate Environmental and Economic Analysis

Section 3 of the Natural Gas Act provides that DOE/FE cannot authorize exports unless it finds the exports to be in the public interest. 15 U.S.C. § 717b. DOE/FE must consider environmental factors in the course of this public interest analysis. Accordingly, DOE/FE cannot proceed with Southern LNG's application without fully evaluating the environmental impacts of Southern LNG's proposal. The National Environmental Policy Act ("NEPA"), 42 U.S.C. § 4332 *et seq*., provides the congressionally mandated procedure for assessment of these impacts, and NEPA requires that these procedures be completed "at the earliest possible time," *i.e.*, "*before* decisions are made and *before* actions are taken." 40 C.F.R. §§ 1501.2, 1500.1(b) (emphases added). Accordingly, DOE/FE cannot proceed with Southern LNG's request for conditional export authorization until the NEPA process is completed, including preparation of an Environmental Impact Statement.

Southern LNG's application largely fails to discuss the environmental impacts of its proposal. The application merely states that the proposal "will have minimal environmental impacts given that, following construction, the export facilities will be located within the previously authorized footprint of the existing Elba Island Terminal." App. at 36. Although the application concedes potential "impacts associated with construction and operation" of the proposed facility, it defers discussion of those impacts pending completion of the NEPA process by the Federal Energy Regulatory Commission. App. at 36-37. Moreover, the application makes no mention of the many impacts associated with the increased production of natural gas that would result from a decision by DOE/FE to grant Southern LNG's request. For this and other reasons, Southern LNG fails to demonstrate that its proposal is in the public interest.

As we explain below, the proposal will cause three types of significant environmental harm. First, the construction and operation of the terminal, liquefaction facilities, and any other associated infrastructure will directly impact local water quality, habitats, and air quality. Second, the project will induce additional natural gas production in the United States, primarily hydraulic fracturing ("fracking") of unconventional gas sources, thus causing the myriad environmental harms associated with such production. Third, the project will increase domestic gas prices, likely causing an increase in coal-fired electricity generation and thus increasing emissions of greenhouse gases and conventional, and toxic air pollutants.

Southern LNG's economic arguments in support of its proposal are unpersuasive. Contrary to Southern LNG's contentions, LNG export will significantly increase domestic gas prices, harming domestic consumers and, as noted above, increased coal-fired electricity generation. Moreover, Southern LNG's predictions of job creation and other economic benefit are overstated. These predictions are derived from a flawed input-output model that provide no consideration of counterfactuals and are therefore unable to identify which of the purportedly "supported" jobs and benefits would have existed anyway. Southern LNG's economic benefits arguments also ignore the substantial distributional inequalities that exports would herald.

For these reasons and the other reasons set forth below, Sierra Club files this protest, pursuant to 10 C.F.R. § 590.304.

A. Legal Standards

DOE/FE has significant substantive and procedural obligations to fulfill before it can authorize Southern LNG's export proposal. Here, we discuss some of these obligations created by the Natural Gas Act, National Environmental Policy Act, Endangered Species Act, and the National Historic Preservation Act before explaining why these obligations preclude Southern LNG's request for conditional authorization.

1. Natural Gas Act

Pursuant to the Natural Gas Act and subsequent delegation orders, DOE/FE must determine whether Southern LNG's proposal to export LNG to nations which have not signed a free trade agreement (FTA) with the United States is in the public interest.[3] Courts, the Federal Energy Regulatory Commission (FERC), and DOE/FE, all agree – and Southern LNG does not contest – that the "public interest" at issue in this provision includes environmental impacts.

Section 3 of the Act provides:

> [N]o person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of [DOE/FE] authorizing it do so. [DOE/FE] shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed exportation or importation will not be consistent with the public interest.

[3] The Natural Gas Act separately provides that DOE/FE must approve exports to nations that have signed a free trade agreement requiring national treatment for trade in natural gas "without modification or delay." 15 U.S.C. § 717b(c). DOE/FE has previously authorized Southern LNG to export 1.25 bcf/d LNG to such nations. DOE/FE Order No. 3100 (May 31, 2012).

15 U.S.C. § 717b(a).[4]

Courts interpreting this provision have held that the “public interest” encompasses the environment. Although the public interest inquiry is rooted in the Natural Gas Act’s “fundamental purpose [of] assur[ing] the public a reliable supply of gas at reasonable prices,” *United Gas Pipe Line Co v. McCombs*, 442 U.S. 529 (1979), the Natural Gas Act also grants DOE/FE “authority to consider conservation, environmental, and antitrust questions.” *NAACP v. Federal Power Comm’n*, 425 U.S. 662, 670 n.4 (1976) (citing 15 U.S.C. § 717b as an example of a public interest provision); *see also id.* at 670 n.6 (explaining that the public interest includes environmental considerations). In interpreting an analogous public interest provision applicable to hydroelectric power and dams, the Court has explained that the public interest determination “can be made only after an exploration of all issues relevant to the ‘public interest,’ including future power demand and supply, alternate sources of power, the public interest in preserving reaches of wild rivers and wilderness areas, the preservation of anadromous fish for commercial and recreational purposes, and the protection of wildlife.” *Udall v. Fed. Power Comm'n*, 387 U.S. 428, 450 (1967) (interpreting § 7(b) of the Federal Water Power Act of 1920, as amended by the Federal Power Act, 49 Stat. 842, 16 U.S.C. § 800(b)). Other courts have applied *Udall*’s holding to the Natural Gas Act. *See, e.g.*, *N. Natural Gas Co. v. Fed. Power Comm'n*, 399 F.2d 953, 973 (D.C. Cir. 1968) (interpreting section 7 of the Natural Gas Act).[5]

DOE has also acknowledged the breadth of the public interest inquiry and recognized that it encompasses environmental concerns. Deputy Assistant Secretary Smith recently testified that “[a] wide range of criteria are considered as part of DOE’s public interest review process, including . . . U.S. energy security . . . [i]mpact on the U.S. economy . . . [e]nvironmental considerations . . . [and] [o]ther issues raised by commenters and/or

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[4] The statute vests authority in the “Federal Power Commission,” which has been dissolved. DOE/FE has been delegated the former Federal Power Commission’s authority to authorize natural gas exports. Department of Energy Redelegation Order No. 00-002.04E (Apr. 29, 2011). The Federal Energy Regulatory Commission has separately been delegated authority regarding the permitting, siting, construction and operation of export facilities. Department of Energy Delegation Order No. 00-004.00A. *See also* Executive Orders 12038 & 10485 (vesting any executive authority to allow construction of export facility in the Federal Power Commission and its successors).

[5] Further support for the inclusion of environmental factors in the public interest analysis is provided by NEPA, which declares that all federal agencies must seek to protect the environment and avoid “undesirable and unintended consequences.” 42 U.S.C. 4331(b)(3).

interveners deemed relevant to the proceeding."[6] DOE rules require export applicants to provide information documenting "[t]he potential environmental impact of the project." 10 C.F.R. § 590.202(b)(7). In a previous LNG export proceeding, DOE determined that the public interest inquiry looks to "domestic need" as well as "other considerations" that included the environment. *Phillips Alaska Natural Gas Corporation and Marathon Oil Company*, 2 FE ¶ 70,317, DOE FE Order No. 1473, *22 (April 2, 1999); *accord* Opinion and Order Conditionally Granting Long-Term Authorization to Export [LNG] from Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations ("*Sabine Pass*"), DOE/FE Order 2961 at 29 (May 20, 2011) (acknowledging that the public interest inquiry extends beyond effects on domestic natural gas supplies). Finally, DOE has applied its "policy guidelines" regarding the public interest to focus review "on the domestic need for the natural gas proposed to be exports; whether the proposed exports pose a threat to the security of natural gas supplies, *and any other issue determined to be appropriate*." *Sabine Pass* at 29 (citing 49 Fed. Reg. 6,684 (Feb. 22, 1984)) (emphasis added).[7]

FERC has agreed that environmental issues are included in the public interest calculus. In FERC's recent order approving siting, construction, and operation of LNG export facilities in Sabine Pass, Louisiana, FERC considered potential environmental impacts of the terminal as part of its public interest assessment, which is analogous to DOE/FE's. 139 FERC ¶ 61,039, PP 29-30 (Apr. 14, 2012).[8]

Southern LNG likewise acknowledges that the public interest inquiry is broad, and includes discussion (albeit brief) of environmental impacts in its application. App. at 15, 36-37.

Although DOE/FE has adopted a presumption that LNG export applications are consistent with the public interest, this presumption is rebuttable and not determinative. The D.C. Circuit has explained to DOE/FE that this presumption is "highly flexible, creating *only* rebuttable presumptions and leaving parties free to assert other factors." *Panhandle Producers & Royalty Owners Ass'n v. Economic Regulatory Admin.*, 822 F.2d 1105, 1110-11, 1113 (D.C. Cir. 1987) (emphasis added) (internal quotation marks omitted). Put differently, although DOE/FE may "presume" that an application

[6] The Department of Energy's Role in Liquefied Natural Gas Export Applications: Hearing Before the S. Comm. on Energy and Natural Resources, 112th Cong. 4 (2011) (testimony of Christopher Smith, Deputy Assistant Secretary of Oil and Gas), attached as Exhibit 2.

[7] Although germane here, these Policy Guidelines policy guidelines are merely guidelines: they "cannot create a norm binding the promulgating agency." *Panhandle Producers and Royalty Owners Ass'n v. Economic Regulatory Administration*, 822 F.2d 1105, 1110-1111 (D.C. Cir. 1987).

[8] Sierra Club contends that other aspects of this order were wrongly decided, as was FERC's subsequent denial of Sierra Club's petition for rehearing, as we explain below.

should be granted, this presumption is not determinative, and DOE/FE retains an independent duty to determine whether an application is, in fact, in the public interest. *See* 10 C.F.R. § 590.404.

2. National Environmental Policy Act

NEPA requires federal agencies to consider and disclose the "environmental impacts" of proposed agency actions. 42 U.S.C. § 4332(C)(i). This requirement is implemented via a set of procedures that "insure [sic] that environmental information is available to public officials and citizens *before* decisions are made and *before* actions are taken." 40 C.F.R. § 1500.1(b) (emphases added). Agencies must "carefully consider [ ] detailed information concerning significant environmental impacts" and NEPA "guarantees that the relevant information will be made available" to the public. *Dep't of Transp. v. Public Citizen*, 541 U.S. 752, 768 (2004) (quoting *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 349 (1989)). The Council on Environmental Quality (CEQ) directs agencies to "integrate the NEPA process with other planning at the earliest possible time to insure that planning and decisions reflect environmental values." 40 C.F.R. § 1501.2. "It is DOE's policy to follow the letter and spirit of NEPA; comply fully with the [CEQ] Regulations and apply the NEPA review process early in the planning stages for DOE proposals." 10 C.F.R. § 1021.100. DOE has adopted CEQ's NEPA regulations in full. *Id.* § 1021.103. The NEPA rules apply to "any DOE action affecting the quality of the environment of the United States, its territories or possessions." *Id.* § 1021.102.

For purposes of the intersection of NEPA and the NGA, the NGA designated the former Federal Power Commission as the "lead agency" for NEPA purposes. 15 U.S.C. § 717n. The lead agency prepares NEPA documents for an action that falls within the jurisdiction of multiple federal agencies. FERC has since generally filled that role, preparing the NEPA documents for LNG export and import decisions, as it did in *Sabine Pass*. *See* 10 C.F.R. § 1021.342 (providing for interagency cooperation). Whether or not FERC takes a lead role, however, DOE's ultimate NEPA obligations are the same: It may not move forward until the full scope of the action *it* is considering – here, the approval of LNG export – has been properly considered. Thus, if the NEPA analysis FERC prepares in its capacity as lead agency is inadequate to fully inform DOE/FE's decision or discharge DOE/FE's NEPA obligations, DOE/FE must prepare a separate EIS.

NEPA requires preparation of an "environmental impact statement" (EIS) where, as here, the proposed major federal action would "significantly affect[] the quality of the human environment." 42 U.S.C. § 4332(C). DOE/FE regulations similarly provide that "[a]pprovals or disapprovals of authorizations to import or export natural gas . . . involving major operational changes (such as a major increase in the quantity of liquefied natural gas imported or exported)" will "normally require [an] EIS." 10 C.F.R. Part 1021, Appendix D, D9. As we explain in more detail below, a full EIS is required here.

An EIS must describe:

> i. the environmental impact of the proposed action,
>
> ii. any adverse environmental effects which cannot be avoided should the proposal be implemented,
>
> iii. alternatives to the proposed action,
>
> iv. the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and
>
> v. any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

42 U.S.C. § 4332(C). The alternatives analysis "is the heart of the environmental impact statement." 40 C.F.R. § 1502.14. Here, the proposed action is to export LNG from the proposed facility; DOE/FE must consider alternatives to this action. DOE/FE must take care not to define the project purpose so narrowly as to prevent the consideration of a reasonable range of alternatives. *See, e.g.*, *Simmons v. U.S. Army Corps of Eng'rs*, 120 F.3d 664, 666 (7th Cir. 1997). If it did otherwise, it would lack "a clear basis for choice among options by the decisionmaker and the public." *See* 40 C.F.R. § 1502.14.

An EIS must also describe the direct and indirect effects and the cumulative impacts of a proposed action. 40 C.F.R §§ 1502.16, 1508.7, 1508.8; *N. Plains Resource Council v. Surface Transp. Bd.*, 668 F.3d 1067, 1072-73 (9th Cir. 2011). These terms are distinct from one another: Direct effects are "caused by the action and occur at the same time and place." 40 C.F.R. § 1508.8(a). Indirect effects are also "caused by the action" but:

> are later in time or farther removed in distance, but are still reasonably foreseeable. Indirect effects may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate, and related effect on air and water and other natural systems, including ecosystems.

40 C.F.R. § 1508.8(b). Cumulative impacts, finally, are not causally related to the action. Instead, they are:

> the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or

> person undertakes such other actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time.

40 C.F.R. § 1508.7. The EIS must give each of these categories of effect fair emphasis.

Agencies may also prepare "programmatic" EISs, which address "a group of concerted actions to implement a specific policy or plan; [or] systematic and connected agency decisions allocating agency resources to implement a specific statutory program or executive directive." 40 C.F.R. § 1508.17(b)(3); *see also* 10 C.F.R. § 1021.330 (DOE regulations discussing programmatic EISs). As we discuss below, such an EIS is appropriate here.

Finally, while an EIS is being prepared "DOE shall take no action concerning the proposal that is the subject of the EIS" until the EIS is complete and a formal Record of Decision has been issued. 10 C.F.R. § 1021.211. During this time, DOE may take no action which would tend to "limit the choice of reasonable alternatives," or "tend[] to determine subsequent development ." 40 C.F.R. § 1506.1.

3. Endangered Species Act

The Endangered Species Act (ESA) directs that all agencies "shall seek to conserve endangered species." 16 U.S.C. § 1531(c)(1). Consistent with this mandate, DOE/FE must ensure that its approval of the Southern LNG project "is not likely to jeopardize the continued existence of any endangered species . . . or result in the destruction or adverse modification of [critical] habitat of such species." 16 U.S.C. § 1536(a)(2). "Each Federal agency shall review its actions at the earliest possible time to determine whether any action may affect listed species or critical habitat." 50 C.F.R. § 402.14(a); *see also* 16 U.S.C. § 1536(a)(2).

Here, DOE/FE's section 1536 inquiry must be wide-ranging, because Southern LNG's export proposal will increase gas production activities nationwide. Thus, DOE/FE must consider not just species impacts at the proposed project site (although it must at least do that),[9] but the effects of increased gas production across the full region the plant affects.

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[9] In assessing Southern LNG's prior proposal to add storage tanks and increase capacity at the Elba Island import terminal, FERC identified eight listed species (West Indian manatees, wood storks, American alligators, eastern indigo snakes, flatwoods salamanders, Canby's dropwort, pool sprite, and pondberry) as potentially occurring in the project area. FERC Dkt. CP06-470, Letter to Fish and Wildlife Service re Section 7 Consultation for the Elba III Project (Aug. 10, 2007), attached as Exhibit 3. The Fish and Wildlife Service ultimately determined that the expansion project was not likely to

To make this determination, DOE/FE should, first, conduct a biological assessment, including the "results of an on-site inspection of the area affected," "[t]he views of recognized experts on the species at issue," a review of relevant literature, "[a]n analysis of the effects of the action on the species and habitat, including consideration of cumulative effects, and the results of any related studies," and "[a]n analysis of alternate actions considered by the Federal agency for the proposed action." *See* 50 C.F.R. § 402.12(f). If that assessment determines that impacts are possible, DOE/FE must enter into formal consultation with the Fish and Wildlife Service and the National Marine Fisheries Service, as appropriate, to avoid jeopardy to endangered species or adverse modification of critical habitat as a result of its approval of Southern LNG's proposal. 16 U.S.C. § 1536(a), (b).

4. National Historic Preservation Act

DOE/FE must also fulfill its obligations under the National Historic Preservation Act (NHPA) to "take into account the effect of the undertaking on any district, site, building, structure, or object that is included in or eligible for inclusion in the National Register." 16 U.S.C. § 470f; *see also Pit River Tribe v. U.S. Forest Serv.*, 469 F.3d 768, 787 (9th Cir. 2006) (discussing the requirements of the NHPA). Because "the preservation of this irreplaceable heritage is in the public interest," 16 U.S.C. § 470(b)(4), it behooves DOE/FE to proceed with caution.

DOE/FE must, therefore, initiate the NHPA section 106 consultation and analysis process in order to "identify historic properties potentially affected by the undertaking, assess its effects and seek ways to avoid, minimize or mitigate any adverse effects on historic properties." 36 C.F.R. § 800.1(a). NHPA regulations make clear that the scope of a proper analysis is defined by the project's area of potential effects, *see* 36 C.F.R. § 800.4, which in turn is defined as "the geographic area . . . within which an undertaking may directly or indirectly cause alterations in the character or use of historic properties," 36 C.F.R. § 800.16(d). This area is "influenced by the scale and nature of an undertaking," *Id.* The area of potential effects should sweep quite broadly here because, as in the ESA and NEPA contexts, the reach of Southern LNG's proposal extends to the entire area in which it will increase gas production. Thus, to approve Southern LNG's proposal, DOE/FE must first understand and mitigate its impacts on any historic properties which it may affect. *See also* DOE Policy P.141.1 (May 2001) (providing that DOE will fully comply with the NHPA and many other cultural resources preservation statutes).

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adversely affect these species, but noted that its assessment would have to be reconsidered in the event of subsequent modifications not considered in the course of its review. FERC Dkt. CP06-470, Memo regarding correspondence with the US Fish and Wildlife Service (Sept. 25, 2007), attached as Exhibit 4.

The regulations governing this process provide that "[c]ertain individuals and organizations with a demonstrated interest in the undertaking may participate as consulting parties" either "due to the nature of their legal or economic relation to the undertaking or affected properties, or their concern with the undertaking's effects on historic properties." 36 C.F.R. § 800.2(c)(5). Sierra Club meets that test, because the organization and its members are interested in preserving intact historic landscapes for their ecological and social value, and reside through the regions affected by the Southern LNG's proposal. Our members have worked for years to protect and preserve the rich human and natural fabric of these regions, and would be harmed by any damage to those resources. Sierra Club must therefore be given consulting party status under the NHPA for this application.

B. All Pending Export Applications, Pipelines, and Studies Must Be Incorporated Into DOE/FE's NEPA, NGA, and Other Analyses

As explained above, the NGA, NEPA, ESA and NHPA all require DOE/FE's determination to be informed by the context in which the proposed project would occur. DOE/FE's analysis must not be confined to local, direct effects of the particular application; DOE/FE must consider the broader constellation of indirect and cumulative effects. Here, to accurately analyze Southern LNG's application in context, DOE/FE's NEPA review must also take into account the other LNG export proposals pending before DOE/FE and FERC. Further, to ensure adequate consideration of the proposed project's impacts in conjunction with the impacts of other terminal proposals, DOE/FE must not act on Southern LNG's application until DOE/FE has received and evaluated comments on its recently released study on the economic impacts of exports. In addition, the broader backdrop of related and similar projects, in turn, must inform the NEPA alternatives analysis. Finally, NEPA bars DOE/FE from granting conditional authorization prior to completion of the NEPA process, including the above analyses.[10]

1. DOE/FE Must Consider the Cumulative Effect of All Pending Export Proposals, and Should Do So Using a Programmatic EIS

Southern LNG's export proposal is only one of many before DOE/FE. Because the effects of these projects are cumulative, and because each approval alters the price and production effects of exports, DOE/FE must consider these projects' interactions. We note that in two similar proceedings EPA has requested consideration of this broader context. EPA, *Scoping Comments – The Jordan Cove Energy Project LP*, FERC Dkt. Nos. PF12-7 and PF12-17, at 3 (Oct. 29, 2012) ("[W]e recommend discussing the proposed project in the context of the larger energy market, including existing export capacity and export capacity under application to the Department of Energy, and clearly describe

[10] Similarly, Sierra Club protests any request for final, rather than conditional, authorization prior to completion of NEPA review.

how the need for the proposed action has been determined.”),[11] EPA, *Scoping Comments – Cove Point Liquefaction Project*, FERC Dkt. No. PF12-16-000, at 2 (Nov. 15, 2012) (“We recommend discussing the proposed project in the context of the broader energy market, including existing and proposed LNG export capacity.”).[12]

DOE/FE can best conduct this analysis by preparing a programmatic EIS considering the impacts of *all* gas export proposals at once. DOE/FE has the discretion to prepare a programmatic EIS, even if it determines that it does not have the duty to do so. *See* 40 C.F.R. § 1508.18(b)(3); 10 C.F.R. § 1021.330. Such a programmatic EIS would allow DOE/FE and the public to understand these proposals’ relationship and their cumulative environmental and economic impacts, thus improving DOE/FE’s ability to make informed decisions on export applications and allowing DOE/FE, the public, and industry to identify prudent alternatives to serve the public interest and minimize environmental impacts. In acting on the many pending LNG export applications, DOE/FE is making what is functionally a programmatic decision to radically alter the U.S. natural gas market by allowing for large-scale LNG export. DOE/FE should conduct an EIS that is adequate to inform this programmatic decision, rather than conducting piecemeal, application-by-application analysis.

2. DOE/FE Must Not Act Until It Has Thoroughly Reviewed its Recently Released Study of LNG Exports’ Economic Impacts and Comments on the Study

DOE/FE has commissioned two broad studies of exports’ economic impacts. In the first, it requested that the Energy Information Administration (“EIA”) analyze “the impacts of increased domestic natural gas demand, as exports.”[13] We discuss this study in detail in part III.C.1.b below. The EIA Export Study predicts price increases from all gas export scenarios, economic impacts to residential and industrial users, and environmental harm as gas-fired electricity generators switch to coal power.[14] The study did not, however, consider the macroeconomic impacts of these effects.[15]

DOE has also commissioned a second study that will consider macroeconomic impacts, and has committed to withholding final authorization of any pending export application until review of these studies is complete.[16] The second study was recently released,[17]

[11] Attached as Exhibit 5.
[12] Attached as Exhibit 6.
[13] EIA, Effect of Increased Natural Gas Exports on Domestic Energy Markets 1 (2012) (“EIA Export Study”), attached as Exhibit 7.
[14] *Id.* at 6.
[15] *Id.* at 3.
[16] *See* Letter from Christopher Smith, DOE Deputy Assistant Secretary for Oil and Natural Gas, to Representative Edward J. Markey (February 24, 2012), *in* Democratic Staff,

and the agency has invited public comments and has committed to taking the comments into account in acting on pending applications.[18] DOE/FE must honor this commitment to withhold authorization pending full review of the study and the comments submitted on it with respect to Southern LNG's application. Indeed, to the extent DOE/FE relies on the study in completing the NEPA analysis that underpins the agency's decision to grant Southern LNG's application, DOE/FE is required to accept public comments on the study pursuant to ordinary NEPA principles. *See* 40 CFR § 1503.1.

3. The Alternatives Analysis Must Consider This Broader Context

Both NEPA and the NGA require DOE/FE to fully consider alternatives to Southern LNG's proposal. Specifically, the NGA public interest analysis requires an "exploration of all issues relevant to the 'public interest'," an inquiry which the Supreme Court held in *Udall* must be wide-ranging. In that case, which concerned hydropower, the regulatory agency was required to consider, for instance, "alternate sources of power," the state of the power market generally, and options to mitigate impacts on wildlife. 387 U.S. at 450. Here, likewise, DOE/FE must consider alternatives to Southern LNG's export proposal that would better serve the public interest, broadly analyzing other approaches to structuring LNG exports and gas use generally, given exports' sweeping effects on the economy.

NEPA is designed to support this sort of broad consideration. As mentioned, the alternatives analysis is "the heart of the environmental impact statement," designed to offer "clear basis for choice among options by the decisionmaker and the public." 40 C.F.R. § 1502.14. Crucially, the alternatives must include "reasonable alternatives not within the jurisdiction of the lead agency," and must include "appropriate mitigation measures not already included in the proposed action or alternatives." *Id.* Because alternatives are so central to decisionmaking and mitigation, "the existence of a viable but unexamined alternative renders an environmental impact statement inadequate." *Oregon Natural Desert Ass'n*, 625 F.3d at 1122 (internal alterations and citations omitted).

House Natural Resources Comm., *Drill Here, Sell There, Pay More: The Painful Price of Exporting Natural Gas*, App. 1 at 3-4 (2012) (*"*Drill Here, Sell There, Pay More"), attached as Exhibit 8.

[17] NERA Economic Consulting, Macroeconomic Impacts of LNG Exports from the United States (2012), *available at* http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf, attached as Exhibit 9.

[18] Energy Department Releases Study on Natural Gas Exports, Invites Public Comment, http://www.fe.doe.gov/programs/gasregulation/LNGStudy.html (last visited Dec. 5, 2012).

Here, DOE/FE must consider a broad range of alternatives to Southern LNG's proposal, including alternatives that would alter or minimize the economy-wide impacts of the many pending export proposals. Even if DOE/FE does not have jurisdiction to directly order implementation of some of these alternatives, it must include them nonetheless.

DOE/FE should consider, at a minimum and without limitation, the following alternatives:

> (1) Whether, consistent with the EIA Export Study, exports, if allowed, should move forward in smaller quantities or on a slower time table to mitigate the domestic economic and environmental impacts associated with large export volumes or rapid export schedules;
>
> (2) Whether export from other locations would better serve the public interest by mitigating or better distributing economic or environmental impacts;
>
> (3) Whether limitations on the sources of exported gas – e.g., limiting export from particular plays, formations, or regions – would help to mitigate environmental and economic impacts;
>
> (4) Whether to condition export on the presence of an adequate regulatory framework, including the fulfillment of the recommendations for safe production made by the DOE's Shale Gas Subcommittee, would better serve the public interest by ensuring that the production increases associated with export will not increase poorly regulated unconventional gas production;
>
> (5) Whether to delay, deny, or condition exports based upon their effect on the U.S. utility market (including changes in air pollution emissions associated with the impacts of increased export demand on fuel choice);
>
> (6) Whether to require exporters to certify that any unconventional gas produced as a result of their proposal (or shipped through their facilities) has been produced in accordance with all relevant environmental laws and according to a set of best production practices (such as that discussed by the DOE's Shale Gas Subcommittee);
>
> (7) Whether to deny export proposals altogether as contrary to the public interest.

Other alternatives are, no doubt, also available, but DOE/FE must at a minimum consider the possibilities listed above, as they are reasonable and bear directly on the public interest determination before it.

4. DOE/FE May Not Conditionally Approve Southern LNG's Proposal Prior to NEPA Review

Although as a general matter DOE/FE may issue "conditional" orders, *see* 10 C.F.R. § 590.402, this general authority cannot trump DOE's specific rules barring the agency from taking any "action concerning [a] proposal" that is the subject of an EIS, 10 C.F.R. § 1021.211, if that action tends to "limit the choice of reasonable alternatives," or "determine subsequent development." 40 C.F.R. § 1506.1. Here, because FERC, the lead agency for purposes of NEPA review, has not yet completed its review of the proposed project, DOE/FE's regulations prohibit DOE/FE from issuing a conditional authorization now. A conditional approval would limit alternatives, and determine subsequent choices, in precisely the manner the regulations forbid.

The NEPA analysis for the Sabine Pass export proposal, and the conditional approval that DOE/FE issued in that case, illustrate the problem. In *Sabine Pass*, DOE/FE expressed its "conditional" view that the project was in the public interest, conditioned on "the satisfactory completion of the environmental review process [by FERC] and on issuance by DOE/FE of a finding of no significant impact or a record of decision pursuant to NEPA." *Sabine Pass* at 41.

This decision was, first, irrational: As we have discussed at length above, DOE/FE cannot complete a public interest determination without weighing environmental factors. Because these factors are integral to DOE/FE's decision, DOE/FE must weigh environmental interests at the same time that weighs all other interests. It may not parcel them into a separate process without irrationally ignoring important aspects of the problem before it.

Second, DOE/FE's approval, even if nominally "conditional," plainly influenced the NEPA process. In the Sabine Pass EA, although FERC acknowledged that DOE/FE was making a broad public interest determination, FERC functionally treated DOE/FE's decision as already made. As such, in its alternatives analysis, FERC summarily rejected the "no-action" alternative because "the no-action alternative could not meet the purpose and need for the Project."[19] This statement reveals FERC's belief that DOE/FE had already made its decision, and thus that the EA was not truly designed assist DOE/FE in deciding *whether* to allow gas exports. An analysis premised on the understanding that the decision had *not* been made after the conditional approval would not have summarily ruled out the no-action alternative. The fact that FERC felt that it was not free to give the no-action alternative serious consideration indicates that conditional approvals in fact tend to limit alternatives and influence decisionmaking.

[19] FERC, *Environmental Assessment for the Sabine Pass Liquefaction Project*, Dkt. No. CP11-72-000, at 3-1 (2011) ("Sabine Pass EA").

To avoid placing premature and illegal restrictions on its decisionmaking, DOE/FE may not approve the Southern LNG export proposal, conditionally or not, until it has considered all alternatives to doing so through the NEPA and NGA processes.

C. Southern LNG's Proposal Will Have Numerous Harmful Environmental Effects and Is Contrary to The Public Interest

Although the full scope of the proposed facility's environmental impacts will be explored more fully during the environmental review process conducted by FERC, it is already apparent that the terminal is likely to harm the local environment. Southern LNG's proposed exports will also induce environmentally harmful gas production, increase prices domestic consumers and industry pay for natural gas, and increase domestic coal consumption, causing attendant harm to public health and the environment. Southern LNG's application does not address any of these economic and environmental costs. These environmental harms translate into economic damage. If pollution sickens people, or restricts their travel, economic productivity will suffer – as it will, more directly, if clean air and water and adequate waste disposal capacity are not available. Similarly, as landscapes are industrialized, tourism, agricultural, forestry, hunting and angling, and other place-dependent industries will suffer. Thus, DOE/FE must both consider these environmental impacts and monetize them to weigh them against other economic harms in the public interest analysis. DOE/FE must also recognize that LNG's application overstates the economic benefit of its proposal, in part by relying on a faulty economic model that has been extensively criticized by economists.

We explain these deficiencies in the application below. In light of these costs and reduced benefits, if DOE/FE were to make a decision on the available record (rather than engaging in further study of these issues, as is warranted here), DOE/FE would have to conclude that these impacts outweigh any possible benefit of the project.

1. The Project Will Have Significant Adverse Impacts Not Discussed in Southern LNG's Application

Southern LNG's proposal will impose significant environmental costs. The environmental costs fall into three categories: direct effects of the terminal and any associated infrastructure, indirect effects of the additional gas production the project will induce, and non-localized effects resulting from increased domestic gas prices and resulting increases in coal combustion. As we explain below, each of these categories of effects must be considered in DOE/FE's NEPA and NGA analyses, and each weighs against finding that the proposed project is consistent with the public interest.

a. Local Environmental Impacts

Although the full scope of the proposed project's local impacts is not yet known, it is already apparent that the proposed project is likely to cause various local environmental impacts. Construction and operation of the new facilities and enhancement of existing equipment will have significant impacts on air, water, landscapes, and wildlife. These impacts must be considered in both the NEPA analysis and in DOE/FE's public interest determination. We offer preliminary comments on these impacts now, identifying impacts that are likely to occur based on experience with similar projects. Naturally, these impacts cannot be fully identified until additional information is presented in the NEPA process; the Sierra Club expects to provide fuller comments at that time.

i. Local Air Pollution

Construction and operation of the proposed terminal, pipeline, and other facilities will emit harmful carbon monoxide (CO), nitrogen oxides (NOx), volatile organic chemicals (VOC), greenhouse gases (GHGs), sulfur dioxides (SO_x), particulate matter (PM_{10} and $PM_{2.5}$), and hydrogen sulfide (H_2S) pollution.

VOC and NO_x

Operation of LNG export terminals such as the proposed project causes significant emissions of volatile organic chemicals (VOCs) and NOx, emitted directly from project facilities and indirectly from tanker and other ship traffic and operations. For example, Oregon LNG, the proponent of a proposed terminal that would be located in Warrenton, Oregon, estimates that that facility would emit at least 736.1 tons per year (tpy) of NOx and 60.47 tpy of VOCs, excluding anticipated additional emissions from compression equipment.[20] The Sabine Pass LNG project, by contrast, has the potential to emit 2,670 tpy of NOx and 88 tpy of VOCs from the liquefaction component of the terminal.[21]

Construction of LNG export terminals can also emit substantial amounts of NOx and VOCs. For example, construction of the Sabine Pass terminal proposal – which is, like Southern LNG's project, a proposal to convert an LNG import terminal for export – is

[20] FERC Dkt. No. PF12-18, Oregon LNG Resource Report ("RR") 9-16 to 9-19. Moreover, that facility would have also included installation of an additional 90,000 horsepower of compression, the emissions from which are not included in the above totals. *See* FERC Dkt. PF12-20 RR 1-1, 1-42 (Aug. 16, 2012). The documents submitted in connection with that project so far do not specify whether these compressors will be powered by electricity from the grid, natural gas, or some other power source. Because natural gas fired compressors have significant NOx and VOC emissions, total emissions resulting from the project could much higher than the above.

[21] FERC, *Environmental Assessment for the* Sabine Pass *Liquefaction Project*, Dkt. No. CP11-72-000,EA, *supra* n.19, at 2-56, t.2.7-7 (2011) ("Sabine Pass EA").

anticipated to cause up to 195 tpy of NOx emissions and 20 tpy of VOC emissions during the years of heaviest construction.[22]

These emissions will harm the environment by increasing the formation of ground-level ozone. VOCs and NO_x contribute to the formation of ground-level ozone (also called smog). Smog pollution harms human respiratory systems and has been linked to premature death, heart failure, chronic respiratory damage, and premature aging of the lungs.[23] Smog may also exacerbate existing respiratory illnesses, such as asthma and emphysema, or cause chest pain, coughing, throat irritation and congestion. Children, the elderly, and people with existing respiratory conditions are the most at risk from ozone pollution.[24] Significant ozone pollution also damages plants and ecosystems.[25]

Ozone also contributes substantially to global climate change over the short term. According to a recent study by the United Nations Environment Program (UNEP), behind carbon dioxide and methane, ozone is now the third most significant contributor to human-caused climate change.[26]

CO

Operation of LNG export terminals such as the proposed project also causes emissions of CO; the Oregon LNG project, for example, is anticipated to directly emit 150.5 tpy of CO, with an additional 197.18 tpy of marine vessel emissions.[27] The Sabine Pass project has the potential to emit 4,759 tons per year of CO from liquefaction activities.[28]

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[22] *Id.* at 2-52 to 2-53, t.2.7-5 (2011).

[23] EPA, *Proposed New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry: Regulatory Impact Analysis*, 4-25 (July 2011) ("O&G NSPS RIA"), *available at* http://www.epa.gov/ttnecas1/regdata/RIAs/oilnaturalgasfinalria.pdf, attached as Exhibit 10; Jerrett *et al.*, *Long-Term Ozone Exposure and Mortality*, New England Journal of Medicine (Mar. 12, 2009), *available at* http://www.nejm.org/doi/full/10.1056/NEJMoa0803894#t=articleTop, attached as Exhibit 11.

[24] *See* EPA, *Ground-Level Ozone, Health Effects*, *available at* http://www.epa.gov/glo/health.html attached as Exhibit 12. EPA, Nitrogen Dioxide, Health, available at http://www.epa.gov/air/nitrogenoxides/health.html, attached as Exhibit 13.

[25] O&G NSPS RIA, *supra* n.23, at 4-26.

[26] *Id. See also* United Nations Environment Programme and World Meteorological Organization, (2011): *Integrated Assessment of Black Carbon and Tropospheric Ozone: Summary for Decision Makers* (hereinafter "UNEP Report," available at http:// www.unep.org/dewa/Portals/67/pdf/Black_Carbon.pdf), at 7, attached as Exhibit 14.

[27] Oregon LNG RR, *supra* n.20, at 9-16 to 9-18.

[28] Sabine Pass EA, *supra* n.22, at 2-56 t.2.7-7.

Construction of LNG export terminals can also emit substantial amounts of CO. For example, construction of the Sabine Pass terminal is anticipated to cause 164 tpy of CO emissions in the heaviest construction year.[29]

CO can cause harmful health effects by reducing oxygen delivery to the body's organs and tissues.[30] CO can be particularly harmful to persons with various types of heart disease, who already have a reduced capacity for pumping oxygenated blood to the heart. "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."[31]

GHGs

Operation of LNG export terminals such as the proposed project also results in emission of greenhouse gases. The Oregon LNG proposal – including the terminal, pipeline, and associated facilities – is estimated to directly emit over 2.6 million tpy of carbon dioxide equivalent in greenhouse gases (CO_2e), with an additional 118,544.6 tpy emitted by marine vessel traffic.[32] The Sabine Pass proposal has the potential to emit 3.91 million tpy of CO_2e from liquefaction facilities.[33]

Construction of LNG export terminals causes substantial greenhouse gas emissions as well; construction of the Sabine Pass facility would cause as much as 29,274 tpy of greenhouse gas emissions in the heaviest construction years.[34]

These greenhouse gas emissions will increase global warming, harming both the local and global environments. The impacts of global warming include "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."[35] A warming climate will also lead to loss of coastal land in densely populated areas, shrinking snowpack in Western states, increased wildfires, and

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[29] *Id.* at 2-52 to 2-53, t.2.7-5 (2011).

[30] EPA, Carbon Monoxide, Health, http://www.epa.gov/air/carbonmonoxide/health.html, last visited Dec. 14, 2012, attached as Exhibit 15.

[31] *Id.*

[32] Oregon LNG RR, *supra* n.20, at RR 9-16 to 9-19.

[33] Sabine Pass EA, *supra* n.22, at 2-57 t.2.7-8.

[34] *Id.* at 2-53 t.2.7-6.

[35] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. at52,738, 52,791-22 (citing U.S. EPA, 2011 U.S. GREENHOUSE GAS INVENTORY REPORT EXECUTIVE SUMMARY (2011),)), attached as Exhibit 16.

reduced crop yields.[36] More frequent heat waves as a result of global warming have already affected public health, leading to premature deaths, and threats to public health are only expected to increase as global warming intensifies. For example, a warming climate will lead to increased incidence of respiratory and infectious disease, greater air and water pollution, increased malnutrition, and greater casualties from fire, storms, and floods.[37] Vulnerable populations—such as children, the elderly, and those with existing health problems—are the most at risk from these threats.

Sulfur Dioxide

Operation of LNG export terminals such as the proposed project also results in emission of sulfur dioxide. The Oregon LNG proposal, for example, would directly emit an estimated 72 tpy of SO_2, with an additional 80.88 tpy emitted by marine vessel traffic.[38]

Sulfur dioxide causes respiratory problems, including increased asthma symptoms. Short-term exposure to sulfur dioxide has been linked to increased emergency room visits and hospital admissions. Sulfur dioxide reacts in the atmosphere to form particulate matter (PM), an air pollutant which causes a great deal of harm to human health.[39] PM is discussed separately below.

Particulate Matter/Fugitive Dust

Operation of LNG export terminals such as the proposed project also results in emission of particulate matter. For example, the proposed Oregon LNG terminal and compressor stations will directly emit an estimated 14.9 tpy of particulate matter, with an additional 51.2 tpy emitted by marine vessel traffic.[40]

PM consists of tiny particles of a range of sizes suspended in air. Small particles pose the greatest health risk. These small particles include "inhalable coarse particles," which are smaller than 10 micrometers in diameter (PM_{10}), and "fine particles" which are less than 2.5 micrometers in diameter ($PM_{2.5}$). PM_{10} is primarily formed from crushing, grinding or abrasion of surfaces. $PM_{2.5}$ is primarily formed by incomplete combustion of fuels or through secondary formation in the atmosphere.[41]

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[36] *Id.* at 66,532–33.

[37] EPA, *Climate Change, Health and Environmental Effects*, *available at* http://epa.gov/climatechange/effects/health.html, attached as Exhibit 17.

[38] Oregon LNG RR, *supra* n.20, at 9-16 to 9-19.

[39] EPA, Sulfur Dioxide, Health, *available at* http://www.epa.gov/air/sulfurdioxide/health.html, attached as Exhibit 18.

[40] Oregon LNG RR, *supra* n.20, at 9-16 to 9-19.

[41] *See* EPA, Particulate Matter, Health, *available at* http://www.epa.gov/pm/health.html, attached as Exhibit 19; BLM, *West Tavaputs Plateau Natural Gas Full Field Development Plan Final Environmental Impact Statement*

Construction of LNG terminals can also be a significant source of particulate matter as well. Construction PM emissions result from fugitive dust raised by construction activities; dust generated can be substantial, depending on the size of the area disturbed and the nature of the construction activities. For the Sabine Pass proposal, construction was estimated to cause 658 tpy of PM_{10} and 99 tpy of $PM_{2.5}$ fugitive dust emissions, even after application of dust suppressant controls.[42]

PM causes a wide variety of health and environmental impacts. PM has been linked to respiratory and cardiovascular problems, including coughing, painful breathing, aggravated asthma attacks, chronic bronchitis, decreased lung function, heart attacks, and premature death. Sensitive populations, include the elderly, children, and people with existing heart or lung problems, are most at risk from PM pollution.[43] PM also reduces visibility,[44] and may damage important cultural resources.[45] Black carbon, a component of PM emitted by combustion sources such as flares and older diesel engines, also warms the climate and thus contributes to climate change.[46]

ii. Water Quality Impacts

The proposed project may impact water quality in numerous ways. Construction may require water withdrawals, and terminal operations could result in stormwater runoff and discharge and suspension or re-suspension of sediment as a result of dredging and ship transits. Stormwater from the terminal site could contain heavy metals, petroleum products and brake chemicals and compounds that are deleterious to fish and fish habitat. In addition, dredging, construction of in-water facilities, and ship transits all have the potential to suspend or re-suspend sediment in the Savannah River, adversely affecting water quality.

iii. Wildlife

The proposed project can be expected to impact wildlife and species habitat in numerous ways. As mentioned above, FERC identified eight listed species (West Indian manatees, wood storks, American alligators, eastern indigo snakes, flatwoods

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("West Tavaputs FEIS"), at 3-19 (July 2010), *available at* http://www.blm.gov/ut/st/en/fo/price/energy/Oil_Gas/wtp_final_eis.html.

[42] Sabine Pass EA, *supra* n.22, at 2-52 t.2.7-4.

[43] O&G NSPS RIA, *supra* n.23, at 4-19; EPA, Particulate Matter, Health

[44] EPA "Visibility – Basic Information" http://www.epa.gov/visibility/what.html, attached as Exhibit 20.

[45] *See* EPA, Particulate Matter, Health, *supra* n.41; West Tavaputs EIS, *supra* n.41, at 3-19; O&G NSPS RIA, *supra* n.23, at 4-24.

[46] UNEP Report at 6; IPCC (2007) at Section 2.4.4.3.

salamanders, Canby's dropwort, pool sprite, and pondberry) as potentially present in the project area at the time it assessed Southern LNG's prior proposal to add storage tanks and increase capacity at the Elba Island import terminal.[47] These and other species could potentially be impacted as a result of Southern LNG's export terminal proposal.

The Sierra Club intends to submit comments during the NEPA process that more fully explore species impacts in light of the project design. At this point, however, we note that increased ship traffic at the project site could harm manatees, alligators, and other water-dependent species at the site. In addition, noise from construction and compressor operations may harass and displace species. Finally, water intake, which may be needed for numerous purposes, including ship operations, may disturb water-dependent species and risks fish entrainment.

b. Induced Gas Production

Further, and perhaps greater, environmental impacts will result from increased gas production. The EIA; NERA, which recently reported to DOE/FE on the macroeconomic impacts of LNG exports; essentially every other LNG export applicant; and other informed commenters all agree that LNG exports will induce additional production in the United States.[48] The Southern LNG proposal is no exception; Southern LNG directly concedes that its proposal will induce production, App. at 27, and attempts to claim the alleged economic benefits of this induced production in arguing that its proposal is in the public interest, App. at 30.

Available tools allow DOE to predict where increased production will occur, although such localized predictions are not necessary for meaningful analysis of environmental impacts. NEPA and the NGA therefore require DOE/FE to consider the effects of this additional production. Although DOE/FE recently refused to consider induced production in the *Sabine Pass* proceeding, that order is not final, applies the wrong legal standard of foreseeability, and understates DOE's own ability to predict induced drilling.

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[47] FERC Dkt. CP06-470, Letter re Section 7 Consultation for the Elba III Project, *supra* n.9.

[48] Although NERA certainly agrees that LNG exports will induce additional production if they occur, *see, e.g.*, NERA Report, *supra* n.17, at 35, one of NERA's core findings is that exports may *not* occur if baseline assumptions about U.S. reserves and global market dynamics hold true, *see id.* at 37. If this prediction proves true – that is, if economic conditions favoring export do not materialize – then, of course, all of the purported economic benefits of export touted by Southern LNG and described in the NERA study will prove illusory, although the adverse environmental impacts associated with construction of the terminal will nonetheless occur. If, on the other hand, exports do occur, they will plainly induce production, and the impacts of that additional production by be analyzed in NEPA by DOE/FE.

i. Southern LNG's Proposal Will Induce Additional U.S. Gas Production

As Southern LNG itself concedes, its export proposal will increase U.S. gas production. App. at 27 ("[E]xports of domestic LNG will provide an additional market for U.S. production, thereby encouraging exploration, development and production."). Southern LNG's economic impact study estimates an increase in shale gas production of 0.2 bcf/d as a result of its proposed exports and an additional 0.1 bcf/d in non-shale production. App. at appx. A p. 45. Southern LNG's estimate of increased production is roughly consistent with other sources; for example, the Energy Information Administration, in its study of effects of U.S. exports commissioned by DOE/FE, estimated that the majority of exported gas would come from increased production, primarily from shale gas.[49] Specifically, EIA predicts that "about 60 to 70 percent" of the volume of LNG exported would be supplied by increases in domestic production, with the remainder supplied via reductions in domestic consumption of current production. EIA also estimates that "about three quarters of this increased production is from shale sources. "[50] While Southern LNG estimates that about two-thirds of the increased production will come from shale, *see* App. at appx. A p. 45, DOE/FE should rely on the production estimates of its own sister agency rather than on Southern LNG's estimates. DOE/FE is required to consider the impacts of this induced production in making a decision on Southern LNG's application.

EIA and DOE have precise tools enabling them to estimate how U.S. production will change in response to Southern LNG's proposed exports. These tools enable DOE/FE to predict, if necessary, how and when production will increase in individual gas plays. EIA's core analytical tool is the National Energy Modeling System ("NEMS"). NEMS was used to produce the EIA exports study. NEMS models the economy's energy use through a series of interlocking modules that represent different energy sectors on geographic levels.[51] Notably, the "Natural Gas Transmission and Distribution" module already models the relationship between U.S. and Canadian gas production, consumption, and trade, specifically projecting U.S. production, Canadian production, imports from Canada, etc.[52] For each region, the module links supply and demand annually, taking transmission costs into account, in order to project how demand will be met by the transmission system.[53] Importantly, the Transmission Module is *already* designed to

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[49] EIA Export Study, *supra* n.13, at 6, 11.
[50] *Id.* at 6.
[51] Energy Information Administration ("EIA"), *The National Energy Modeling System: An Overview*, 1-2 (2009), attached as Exhibit 21, available at http://www.eia.gov/oiaf/aeo/overview/pdf/0581(2009).pdf.
[52] *Id.* at 59.
[53] EIA, *Model Documentation: Natural Gas Transmission and Distribution Module of the National Energy Modeling System*, 15-16 (2012), attached as Exhibit 22, *available at* http://www.eia.gov/FTPROOT/modeldoc/m062(2011).pdf.

model LNG imports and exports, and contains an extensive modeling apparatus allowing it to do so on the basis of production in the U.S., Canada, and Mexico.[54] At present, the Module focuses largely on LNG imports, reflecting U.S. trends up to this point, but it also already links the Supply Module to the existing Alaskan *export* terminal and projects exports from that site and their impacts on production.[55]

Similarly, the "Oil and Gas Supply" module models individual regions and describes how production responds to demand across the country. Specifically, the Supply Module is built on detailed state-by-state reports of gas production curves across the country.[56] As EIA explains, "production type curves have been used to estimate the technical production from known fields" as the basis for a sophisticated "play-level model that projects the crude oil and natural gas supply from the lower 48."[57] The module distinguishes coalbed methane, shale gas, and tight gas from other resources, allowing for specific predictions distinguishing unconventional gas supplies from conventional supplies.[58] The module further projects the number of wells drilled each year, and their likely production – which are important figures for estimating environmental impacts.[59] In short, the supply module "includes a comprehensive assessment method for determining the relative economics of various prospects based on future financial considerations, the nature of the undiscovered and discovered resources, prevailing risk factors, and the available technologies. The model evaluates the economics of future exploration and development from the perspective of an operator making an investment decision."[60] Thus, for each play in the lower 48 states, the EIA is able to predict future production based on existing data. The model is also equipped to evaluate policy changes that might impact production; according to EIA, "the model design provides the flexibility to evaluate alternative or new taxes, environmental, or other policy changes in a consistent and comprehensive manner."[61]

Thus, there is no technical barrier to modeling where exports will induce production going forward. Indeed, EIA used this model for its export study, which forecast production and price impacts.

EIA is not alone in its ability to predict localized effects of LNG exports. A study and model developed by Deloitte Marketpoint claims the ability to make localized

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[54] *See id.* at 22-32.
[55] *See id.* at 30-31.
[56] EIA, *Documentation of the Oil and Gas Supply Module*, 2-2 (2011), attached as Exhibit 23, *available at* http://www.eia.gov/FTPROOT/modeldoc/m063(2011).pdf.
[57] *Id.* at 2-3.
[58] *Id.* at 2-7.
[59] *See id.* at 2-25 to 2-26.
[60] *Id.* at 2-3.
[61] *Id.*

predictions about production impacts, and numerous other LNG export terminal proponents have relied on this study in applications to FERC and DOE.[62] According to Deloitte, its "North American Gas Model" and "World Gas Model" allow it to predict how gas production, infrastructure construction, and storage will respond to changing demand conditions, including those resulting from LNG export. According to Deloitte, the model connects to a database that contains "field size and depth distributions for every play," allowing the company to model dynamics between these plays and demand centers. "The end result," Deloitte maintains, "is that valuing storage investments, identifying maximally effectual storage field operation, positioning, optimizing cycle times, demand following modeling, pipeline sizing and location, and analyzing the impacts of LNG has become easier and generally more accurate."[63]

ii. Induced Production Must Be Considered in the NEPA and NGA Analyses

NEPA regulations, applicable case law, and recent EPA scoping comments all call for DOE/FE to consider the environmental effects of induced production. As noted above, NEPA requires consideration of "indirect effects" of the proposed action, which include "growth inducing effects" and "reasonably foreseeable" effects "removed in distance" from the site of the proposed action. 40 C.F.R. § 1508.8(b). Here, induced production – which is part of the proffered justification for the proposed project, App. at 30 – is plainly a "reasonably foreseeable" effect that must be analyzed in NEPA.

Several courts have held that natural resource production and other analogous upstream impacts induced by new infrastructure development must be considered in NEPA. For example, the Ninth Circuit recently held that, where the Surface Transportation Board was considering a proposal to expand a railway line which would enable increased coal production at several mines, NEPA required the Board to consider the impacts of increased mining. *N. Plains Resource Council v. Surface Transp. Bd.*, 668 F.3d 1067, 1081-82 (9th Cir. 2011). In *Northern Plains*, the court pointed to the agency's reliance on the induced coal mine development "to justify the financial soundness of the proposal," *id.* at 1082. Because the agency anticipated induced coal production in justifying its proposal, such production was reasonably foreseeable, and NEPA analysis

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[62] Deloitte Marketpoint, *Made in America: The Economic Impact of LNG Exports from the United States* (2011) (hereinafter "*Deloitte Report*"), available at http://www.deloitte.com/assets/Dcom-UnitedStates/Local%20Assets/Documents/Energy_us_er/us_er_MadeinAmerica_LNGPaper_122011.pdf and attached as Exhibit 24.

[63] Deloitte, *Natural Gas Models*, http://www.deloitte.com/view/en_US/us/Industries/power-utilities/deloitte-center-for-energy-solutions-power-utilities/marketpoint-home/marketpoint-data-models/b2964d1814549210VgnVCM200000bb42f00aRCRD.htm (last visited Dec. 20, 2012), attached as Exhibit 25.

of its impacts was required. Here, a decision by DOE/FE to rely on the supposed economic benefits of increased production, while simultaneously ignoring the impacts of this production, would be squarely inconsistent with *Northern Plains*. *Accord Mid States Coalition for Progress v. Surface Transp. Bd.*, 345 F.3d 520, 548-550 (8th Cir. 2003).

Border Power Plant Working Group v. DOE, 260 F. Supp. 2d 997 (S.D. Cal. 2003), also required consideration of upstream environmental impacts induced by the construction of new energy infrastructure. That case involved applications to construct and operate transmission lines across the U.S.-Mexico border. The court held that DOE was required to consider the environmental effects of upstream electricity generation induced by the new infrastructure, rejecting DOE's decision to exclude these upstream impacts from analysis.[64] *Id.* at 1017. Consideration of induced impacts was required even though the upstream electricity generation would occur in Mexico, outside the jurisdiction of DOE or any other U.S. agency. *Id.* at 1016-17. Here, too, DOE/FE is required to consider the impacts of natural gas production induced by Southern LNG's proposal, regardless of DOE's regulatory authority over that production.

EPA has also argued, in scoping comments it submitted regarding two other LNG export proposals, that induced production should be included in NEPA review. In scoping comments for the Jordan Cove project, EPA opined that in light of the regulatory definition of indirect effects and the EIA Export Study's prediction of induced production, "it is appropriate to consider available information about the extent to which drilling activity might be stimulated by the construction of an LNG export facility on the west coast, and any potential environmental effects associated with that drilling expansion."[65] EPA's scoping comments for the Cove Point facility in Maryland also recommended analyzing "indirect effects related to gas drilling and combustion," and stressed that, in addition to reviewing the *economic* impacts of induced drilling, DOE/FE should "thoroughly consider the indirect and cumulative *environmental* impacts" of export.[66]

Although DOE/FE recently "accept[ed] and adopt[ed] [FERC's] determination that induced shale gas production is not a reasonably foreseeable effect [of LNG exports] for purposes of NEPA analysis" in the *Sabine Pass* proceeding, DOE/FE should not follow *Sabine Pass* here. The *Sabine Pass* decision is currently being reconsidered by DOE, so DOE's initial order is not final, *see Sabine Pass* DOE/FE Order 2961-A at 28; Order

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[64] The final EIS for the project at issue in *Border Power Plant Working Group*, produced after remand from the court, is available at: http://energy.gov/nepa/downloads/eis-0365-final-environmental-impact-statement. Upstream air quality impacts are considered in pages 4-43 to 4-65 of this final EIS.
[65] EPA Jordan Cove Scoping Comments, *supra* n.11, at 14 (Exhibit 5).
[66] EPA Cove Point Scoping Comments, *supra* n.12, at 2-3 (Exhibit 6).

Granting Rehearing for Further Consideration, FE Docket 10-111-LNG (Oct. 5, 2012), and in any event the ruling contains factual and legal errors and thus should not be the basis for future DOE/FE decisions.[67]

The first flaw in DOE/FE's *Sabine Pass* decision is that DOE/FE refused to analyze reasonably foreseeable future environmental effects based on its unlawful demand that these effects' scope and nature first be known with a high degree of certainty. DOE/FE stated that it is "unknown" if "any" new production will result from the proposed exports. *Sabine Pass* at 28. Although it is true that the precise scope of production impacts cannot be determined with complete certainty, certainty is not required. "An impact is 'reasonably foreseeable' if it is 'sufficiently likely to occur that a person of ordinary prudence would take it into account in reaching a decision.'" *City of Shoreacres v. Waterworth*, 420 F.3d 440, 453 (5th Cir. 2005) (quoting *Sierra Club v. Marsh*, 976 F.2d 763, 767 (1st Cir. 1992)).[68] NEPA requires "[r]easonable forecasting and speculation," and courts "must reject any attempt by agencies to shirk their responsibilities under NEPA by labeling any and all discussion of future environmental effects as 'crystal ball inquiry.'" *Scientists' Inst. for Pub. Info., Inc. v. Atomic Energy Comm'n*, 481 F.2d 1079, 1092 (D.C. Cir. 1973). As explained above, every available source concludes that it is *likely* that the majority of exported gas will come from induced additional production. Thus, if exports occur, an aggregate production increase is unarguably "reasonably foreseeable."

DOE/FE's second error in *Sabine Pass* was to adopt FERC's conclusion that induced production was outside the scope of NEPA analysis because "while it may be the case that additional shale gas development will result from the Liquefaction Project, the amount, timing and location of such development activity is simply unknowable at this time." *Sabine Pass* at 13 (quoting 140 FERC ¶ 61,076, P9 (July 26, 2012)). Such specific, localized predictions are not required for meaningful environmental analysis, but even if they were, DOE/FE has the resources to provide them.

As a threshold matter, analysis of the environmental impacts of induced gas production does not require knowledge of the precise sites where additional production will occur. Environmental costs (and the economic costs that accompany them) can be determined in the aggregate. The net increases in, for instance, air pollution associated with the number of wells that will be induced can be quantified based on EPA's emissions

[67] DOE is not bound by its prior decisions: it may reverse its position "with or without a change in circumstances" so long as it provides "a reasoned analysis" for the change. *Louisiana Pub. Serv. Comm'n v. FERC*, 184 F.3d 892, 897 (D.C. Cir. 1999) (quoting *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 57 (1983)).
[68] In this proceeding, FERC endorses this formulation of "reasonable foreseeability." FERC "Order Granting Section 3 Authorization" 139 FERC ¶ 61,039, FERC Docket CP11-72-001 ¶ 95(April 16, 2012) (hereinafter "FERC April Order").

inventories, for instance. The net volumes of waste can similarly be derived from industry reports and state discharge figures. And these impacts can be localized, at a minimum, by region. Indeed, for many of the environmental impacts of production, such as emissions of many air pollutants and consumption of water, the impacts are likely to be experienced at the regional level, so there would be little value in localizing them further. Even for those impacts that are more closely tied to a specific location, such as habitat fragmentation, DOE/FE can and must acknowledge that the impact will occur, including an estimate of the severity of the impact averaged across potential locations. *See Scientists' Inst. for Pub. Info.*, 481 F.2d at 1096-97 (where there are reasonable estimates of the deployment of nuclear power plants, the amount of waste produced, and the land needed to store waste, NEPA required analysis of the impacts of such storage even though the agency could not predict *where* such storage would occur).

Even if DOE/FE were to conclude, wrongly, that NEPA only requires analysis of induced drilling impacts that can be predicted to occur in a particular location, DOE/FE has the tools to make precisely that prediction, as explained in the previous section. If such local impact predictions are not yet in the record, NEPA regulations provide that DOE/FE "shall" obtain this information unless DOE/FE demonstrates that the costs of obtaining it are "exorbitant." 40 C.F.R. §1502.22.

In summary, all the available evidence indicates that Southern LNG's proposed exports will induce additional gas production in the U.S. This increase is reasonably foreseeable, and its environmental effects must be analyzed under NEPA.

iii. Environmental Harm Resulting from Induced Production

Natural gas production—from both conventional and unconventional sources—is a significant air pollution source, can disrupt ecosystems and watersheds, leads to industrialization of entire landscapes, and presents challenging waste disposal issues. EIA must consider the increase in these environmental harms that exports are likely to stimulate.

Much of the induced production resulting from exports is likely to come from shale gas and other unconventional sources. EIA has concluded that "[o]n average, across all cases and export scenarios, the shares of the increase in total domestic production coming from shale gas, tight gas, [and] coalbed sources are 72 percent, 13 percent, [and] 8 percent," respectively.[69] A subcommittee of the DOE's Secretary of Energy's Advisory Board recently highlighted "a real risk of serious environmental consequences" resulting from continued expansion of shale gas production. DOE, Secretary of Energy's Advisory Board, *Shale Gas Production Subcommittee Second 90-Day Report* (2011) at

[69] EIA Export Study, *supra* n. 13, at 11 (Exhibit 7).

10.[70] Shale gas production (as well as coalbed and tight sands production) requires the controversial practice of hydraulic fracturing, or fracking. As we explain below, natural gas production in general, and fracking in particular, impose a large number of environmental harms. Although some states and federal agencies are taking steps to limit these harms, these efforts are uncertain and, even if fully implemented, will not eliminate the environmental harms.

1. Natural Gas Production is a Major Source of Air Pollution

Below, we briefly describe some of the primary air pollution problems caused by the industry. These issues include direct emissions from production equipment and indirect emissions caused by natural gas replacing cleaner energy sources. EPA has moved to correct some of these problems with new air regulations finalized this year, but, as we later discuss, these standards do not fully address the problem. FERC must therefore consider the air pollution impacts of increased natural gas production even if EPA's rules are finalized.

Air Pollution Problems from Natural Gas

Oil and gas operations emit methane (CH_4), volatile organic compounds (VOCs), nitrogen oxides (NO_x), sulfur dioxide (SO_2), hydrogen sulfide (H_2S), and particulate matter (PM_{10} and $PM_{2.5}$). Oil and natural gas operations also emit listed hazardous air pollutants (HAPs) in significant quantities, and so contribute to cancer risks and other acute public health problems. Pollutants are emitted during all stages of natural gas development, including (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission, and (4) natural gas distribution.[71] Within these development stages, the major sources of air pollution include wells, compressors, pipelines, pneumatic devices, dehydrators, storage tanks, pits and ponds, natural gas processing plants, and trucks and construction equipment.

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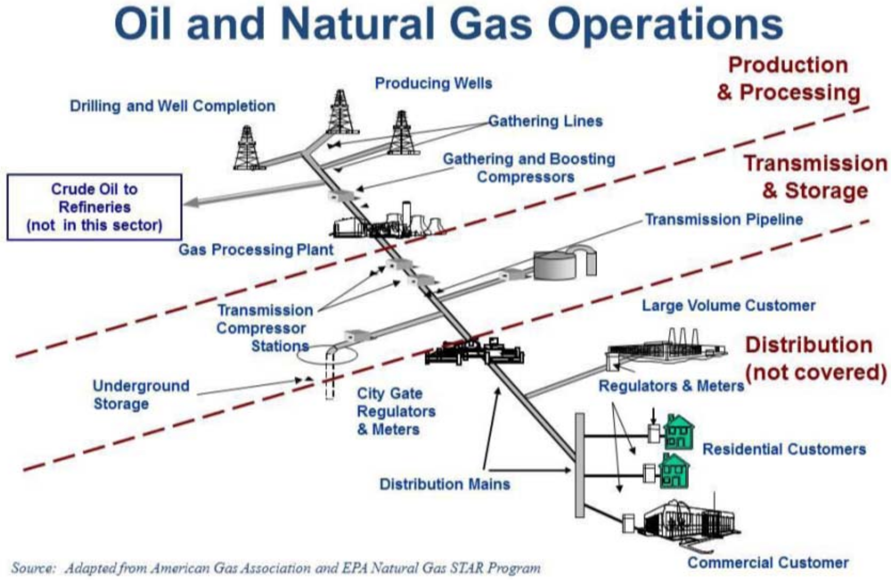
[70] Attached as Exhibit 26. *See also* DOE, Shale Gas Production Subcommittee First 90-Day Report, attached as Exhibit 27.

[71] EPA, Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution, Background Technical Support Document for the Proposed Rules ("TSD") at 2-4 (July 2011), attached as Exhibit 28.

Figure 1: The Oil and Natural Gas Sector



There is strong evidence that emissions from natural gas production are higher than have been commonly understood. In particular, a recent study by a consortium of researchers led by the National Ocean and Atmospheric Administration (NOAA) Earth System Research Laboratory recorded pollution concentrations near gas fields substantially greater than EPA estimates would have predicted. That study monitored air quality around oil and gas fields.[72] The researchers observed high levels of methane, propane, benzene, and other volatile organic compounds in the air around the fields. According to the study authors, their "analysis suggests that the emissions of the species we measured" – that is, the cancer-causing, smog-forming, and climate-disrupting pollutants released from these operations – "are most likely underestimated in current inventories," perhaps by as much as a factor of two.[73]

These emissions have dire practical consequences. A second research team, led by the Colorado School of Public Health, measured benzene and other pollutants released from unconventional well completions.[74] Elevated levels of these pollutants correspond to

[72] G. Petron *et al.*, *Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study*, 117 J. of Geophysical Research 4304, DOI 10.1029/2011JD016360 (2012), attached as Exhibit 29.
[73] *Id.* at 4304.
[74] L. McKenzie *et al.*, *Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources*, Science of the Total Environment (In Press, Mar. 22, 2012), attached as Exhibit 30.

increased cancer risks for people living within half of a mile from a well[75] – a very large population which will increase as drilling expands.

We discuss the harmful effects of many of these pollutants in part III.C.1.a, above. Below, we detail the sources of emissions within the gas production industry and provide further information regarding the serious global, regional, and local impacts these exploration and production emissions entail:

Methane: Methane is the dominant pollutant from the oil and gas sector. Emissions occur as result of intentional venting or unintentional leaks during drilling, production, processing, transmission and storage, and distribution. For example, methane is emitted when wells are completed and vented, as part of operation of pneumatic devices and compressors, and as a result of leaks (fugitive emissions) in pipelines, valves, and other equipment. EPA has identified natural gas systems as the "single largest contributor to United States anthropogenic methane emissions."[76] The industry is responsible for over 40% of total U.S. methane emissions.[77] Methane causes harm both because of its contributions to climate change and as an ozone precursor.

Methane is a potent greenhouse gas that contributes substantially to global climate change. Methane has at least 25 times the global warming potential of carbon dioxide over a 100 year time frame and at least 72 times the global warming potential of carbon dioxide over a 20-year time frame.[78] Because of methane's effects on climate, EPA has found that methane, along with five other well-mixed greenhouse gases, endangers public health and welfare within the meaning of the Clean Air Act.[79] The oil and gas production industry is a significant emitter of this dangerous pollutant; its methane emissions amount to 5% of all carbon dioxide equivalent (CO_2e) emissions in the country.[80]

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[75] *Id.* at 2.

[76] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 Fed. Reg. 52,738, 52,792 (Aug. 23, 2011), attached as Exhibit 31. 76 Fed. Reg. 52,738, *supra* n.35, at 52,792.

[77] *Id.* at 52,791–92.

[78] *IPCC 2007—The Physical Science Basi*s, Section 2.10.2, and *IPCC 2007- Summary for Policymakers*, attached as Exhibit 32. We note that these global warming potential figures may be revised upward in the next IPCC report. A more recent study by Shindell *et al.* estimates methane's 100-year GWP at 33; this same source estimates methane's 20-year GWP at 105.

[79] EPA, Endangerment and Cause or Contribute Findings for Greenhouse Gases, 74 Fed. Reg. 66,496, 66,516 (Dec. 15, 2009) ("Endangerment Finding"), attached as Exhibit 33.

[80] 76 Fed. Reg. 52,738, *supra* n.7635, at 52,791–92.

Methane also reacts in the atmosphere to form ozone.[81] As we discuss elsewhere, ozone is a major public health threat, linked to a wide range of maladies. In addition to these public health harms, ozone can damage vegetation, agricultural productivity, and cultural resources. Ozone is also a greenhouse gas, meaning that methane is doubly damaging to climate – first in its own right, and then as an ozone precursor.

***Volatile Organic Compounds (VOCs) and NO_x*:** The gas industry is also a major source of two other ozone precursors: VOCs and NO_x.[82] VOCs are emitted from well drilling and completions, compressors, pneumatic devices, storage tanks, processing plants, and as fugitives from production and transmission.[83] The primary sources of NO_x are compressor engines, turbines, and other engines used in drilling and hydraulic fracturing.[84] NO_x is also produced when gas is flared or used for heating.[85]

As a result of significant VOC and NO_x emissions associated with oil and gas development, numerous areas of the country with heavy concentrations of drilling are now suffering from serious ozone problems. For example, the Dallas Fort Worth area in Texas is home to substantial oil and gas development. Within the Barnett shale region, as of September 2011, there were more than 15,306 gas wells and another 3,212 wells permitted.[86] Of the nine counties surrounding the Dallas Fort Worth area that EPA has designated as "nonattainment" for ozone, five contain significant oil and gas development.[87] A 2009 study found that summertime emissions of smog-forming pollutants from these counties were roughly comparable to emissions from motor vehicles in those areas.[88]

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[81] *Id.* at 52,791.

[82] *See, e.g.*, Al Armendariz, Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements (Jan. 26, 2009), available at http://www.edf.org/documents/9235_Barnett_Shale_Report.pdf (hereinafter "Barnett Shale Report") at 24, attached as Exhibit 34.

[83] *See, e.g.,* TSD, *supra* n.71, at 4-7, 5-6, 6-5, 7-9, 8-1 (Exhibit 28); *see also* Barnett Shale Report, *supra* n.82, at 24 (Exhibit 34).

[84] *See, e.g.*, TSD, *supra* n.71, at 3-6; Barnett Shale Report, *supra* n.82, at 24 (Exhibit 34); Air Quality Impact Analysis Technical Support Document for the Revised Draft Supplemental Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project at 11 (Table 2.1).), attached as Exhibit 35.

[85] TSD, *supra* n.71, at 3-6; Colorado Department of Public Health and Environment, *Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado*, Appendix D at 1 (2011), available at http://www.cdphe.state.co.us/ap/RegionalHaze/AppendixD/4-FactorHeaterTreaters07JAN2011FINAL.pdf, attached as Exhibit 36.

[86] Texas Railroad Commission history of Barnett Shale, attached as Exhibit 37.

[87] Barnett Shale Report, *supra* n.82, at 1, 3 (Exhibit 34).

[88] *Id.* at 1, 25-26.

Oil and gas development has also brought serious ozone pollution problems to rural areas, such as western Wyoming.[89] On March 12, 2009, the governor of Wyoming recommended that the state designate Wyoming's Upper Green River Basin as an ozone nonattainment area.[90] The Wyoming Department of Environmental Quality conducted an extended assessment of the ozone pollution problem and found that it was "primarily due to local emissions from oil and gas . . . development activities: drilling, production, storage, transport, and treating."[91] Last winter alone, the residents of Sublette County suffered thirteen days with ozone concentrations considered "unhealthy" under EPA's current air-quality index, including days when the ozone pollution levels exceeded the worst days of smog pollution in Los Angeles.[92] Residents have faced repeated warnings regarding elevated ozone levels and the resulting risks of going outside.[93]

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[89] Schnell, R.C, *et al*. (2009), "Rapid photochemical production of ozone at high concentrations in a rural site during winter," *Nature Geosci.* 2 (120 – 122). DOI: 10.1038/NGEO415, attached as Exhibit 38.

[90] *See* Letter from Wyoming Governor Dave Freudenthal to Carol Rushin, Acting Regional Administrator, USEPA Region 8, (Mar. 12, 2009) ("Wyoming 8-Hour Ozone Designation Recommendations"), *available at* http://deq.state.wy.us/out/downloads/Rushin%20Ozone.pdf, attached as Exhibit 39; Wyoming Department of Environmental Quality, Technical Support Document I for Recommended 8-hour Ozone Designation of the Upper Green River Basin (March 26, 2009) ("Wyoming Nonattainment Analysis"), at vi-viii, 23-26, 94-05, *available at* http://deq.state.wy.us/out/downloads/Ozone%20TSD_final_rev%203-30-09_jl.pdf, attached as Exhibit 40.

[91] Wyoming Nonattainment Analysis, *supra* n.90, at viii (Exhibit 39).

[92] EPA, *Daily Ozone AQI Levels in 2011 for Sublette County, Wyoming*, *available at* http://www.epa.gov/cgi-bin/broker?msaorcountyName=countycode &msaorcountyValue=56035&poll=44201&county=56035&msa=-1&sy=2011&flag=Y &_debug=2&_service=data&_program=dataprog.trend_tile_dm.sas, attached as Exhibit 41; *see also* Wendy Koch, *Wyoming's Smog Exceeds Los Angeles' Due to Gas Drilling*, USA Today, *available at* http://content.usatoday.com/communities/greenhouse/post/2011/03/wyomings-smog-exceeds-los-angeles-due-to-gas-drilling/1, attached as Exhibit 42.

[93] *See, e.g.*, 2011 DEQ Ozone Advisories, Pinedale Online! (Mar. 17, 2011), http://www.pinedaleonline.com/news/2011/03/OzoneCalendar.htm (documenting ten ozone advisories in February and March 2011), attached as Exhibit 43; Wyoming Department of Environmental Quality, Ozone Advisory for Monday, Feb. 28, Pinedale Online! (Feb. 27, 2011), http://www.pinedaleonline.com/news/2011/02/OzoneAdvisoryforMond.htm, attached as Exhibit 44.

Ozone problems are mounting in other Rocky Mountain states as well. Northeastern Utah recorded unprecedented ozone levels in the Uintah Basin in 2010 and 2011. In the first three months of 2010—which was the first time that winter ozone was monitored in the region—air quality monitors measured more than 68 exceedances of the federal health standard. On three of these days, the levels were almost twice the federal standard.[94] Between January and March 2011, there were 24 days where the National Ambient Air Quality Standard (NAAQS) for ozone were exceeded in the area. Again, ozone pollution levels climbed to nearly twice the federal standard.[95] The Bureau of Land Management (BLM) has identified the multitude of oil and gas wells in the region as the primary cause of the ozone pollution.[96]

Rampant oil and gas development in Colorado and New Mexico is also leading to high levels of VOCs and NO_x. In 2008, the Colorado Department of Public Health and Environment concluded that the smog-forming emissions from oil and gas operations exceed vehicle emissions for the entire state.[97] Moreover, significant additional drilling has occurred since 2008. Colorado is now home to more than 46,000 wells.[98] There is also significant development in the San Juan Basin in southeastern Colorado and northwestern New Mexico, with approximately 35,000 wells in the Basin. As a result of this development and several coal-fired power plants in the vicinity, the Basin suffers from serious ozone pollution.[99] This pollution is taking a toll on residents of San Juan

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[94] Scott Streater, *Air Quality Concerns May Dictate Uintah Basin's Natural Gas Drilling Future*, N.Y. TIMES, Oct. 1, 2010, *available at* http://www.nytimes.com/gwire/2010/10/01/01greenwire-air-quality-concerns-may-dictate-uintah-basins-30342.html, attached as Exhibit 45.

[95] *See* EPA, AirExplorer, Query Concentrations (Ozone, Uintah County, 2011), available through the http://www.epa.gov/airexplorer/ website and attached as Exhibit 46.

[96] BLM, *GASCO Energy Inc. Uinta Basin Natural Gas Development Draft Environmental Impact Statement* ("GASCO DEIS"), at 3-13, *available at* http://www.blm.gov/ut/st/en/fo/vernal/planning/nepa_/gasco_energy_eis.html, attached as Exhibit 47.

[97] Colo. Dept. of Public Health & Env't, Air Pollution Control Division, Oil and Gas Emission Sources, *Presentation for the Air Quality Control Commission Retreat*, at 3-4 (May 15, 2008), attached as Exhibit 48.

[98] Colorado Oil & Gas Conservation Commission, *Colorado Weekly & Monthly Oil and Gas Statistics*, at 12 (Nov. 7, 2011), available at http://cogcc.state.co.us/ (library—statistics—weekly/monthly well activity), attached as Exhibit 49.

[99] *See Four Corners Air Quality Task Force Report of Mitigation Options*, at vii (Nov. 1, 2007), *available at* http://www.nmenv.state.nm.us/aqb/4C/TaskForceReport.html, attached as Exhibit 50.

County. The New Mexico Department of Public Health has documented increased emergency room visits associated with high ozone levels in the County.[100]

VOC and NO_x emissions from oil and gas development are also harming air quality in national parks and wilderness areas. Researchers have determined that numerous "Class I areas" – a designation reserved for national parks, wilderness areas, and other such lands[101] – are likely to be impacted by increased ozone pollution as a result of oil and gas development in the Rocky Mountain region. Affected areas include Mesa Verde National Park and Weminuche Wilderness Area in Colorado and San Pedro Parks Wilderness Area, Bandelier Wilderness Area, Pecos Wilderness Area, and Wheeler Peak Wilderness Area in New Mexico.[102] These areas are all near concentrated oil and gas development in the San Juan Basin.[103]

As oil and gas development moves into new areas, particularly as a result of the boom in development of shale resources, ozone problems are likely to follow. For example, regional air quality models predict that gas development in the Haynesville shale will increase ozone pollution in northeast Texas and northwest Louisiana and may lead to violations of ozone NAAQS.[104]

Sulfur dioxide: Oil and gas production also emits sulfur dioxide, primarily from natural gas processing plants.[105] Sulfur dioxide is released as part of the sweetening process, which removes hydrogen sulfide from the gas.[106] Sulfur dioxide is also created when gas containing hydrogen sulfide (discussed below) is combusted in boilers or heaters.[107]

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[100] Myers *et al.*, *The Association Between Ambient Air Quality Ozone Levels and Medical Visits for Asthma in San Juan County* (Aug. 2007), *available at* http://www.nmenv.state.nm.us/aqb/4c/Documents/SanJuanAsthmaDocBW.pdf, attached as Exhibit 51.

[101] *See* 42 U.S.C. § 7472(a).

[102] Rodriguez et al., *Regional Impacts of Oil and Gas Development on Ozone Formation in the Western United States*, 59 Journal of the Air and Waste Management Association 1111 (Sept. 2009), available at http://www.wrapair.org/forums/amc/meetings/091111_Nox/Rodriguez_et_al_OandG_Impacts_JAWMA9_09.pdf, attached as Exhibit 52.

[103] *Id.* at 1112.

[104] *See* Kemball-Cook et al., *Ozone Impacts of Natural Gas development in the Haynesville Shale* 44 Environ. Sci. Technol. 9357, 9362 (2010), attached as Exhibit 53.

[105] 76 Fed. Reg., *supra* n.76, at 52,756.

[106] TSD, *supra* n.71, at 3-3 to 3-5.

[107] 76 Fed. Reg. , *supra* n.76, at 52,756.

Hydrogen sulfide: Some natural gas contains hydrogen sulfide. Gas containing hydrogen sulfide above a specific threshold is classified as "sour gas."[108] According to EPA, there are 14 major areas in the U.S., found in 20 different states, where natural gas tends to be sour.[109] All told, between 15 and 20% of the natural gas in the U.S. may contain hydrogen sulfide.[110]

Given the large amount of drilling in areas with sour gas, EPA has concluded that the potential for hydrogen sulfide emissions from the oil and gas industry is "significant."[111] Hydrogen sulfide may be emitted during all stages of development, including exploration, extraction, treatment and storage, transportation, and refining.[112] For example, hydrogen sulfide is emitted as a result of leaks from processing systems and from wellheads in sour gas fields.[113]

Hydrogen sulfide emissions from the oil and gas industry are concerning because this pollutant may be harmful even at low concentrations.[114] Hydrogen sulfide is an air pollutant with toxic properties that smells like rotten eggs and can lead to neurological impairment or death. Long-term exposure to hydrogen sulfide is linked to respiratory infections, eye, nose, and throat irritation, breathlessness, nausea, dizziness, confusion, and headaches.[115] Although hydrogen sulfide was originally included in the Clean Air Act's list of hazardous air pollutants, it was removed with industry support.[116]

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[108] *Id.* at 52,756. Gas is considered "sour" if hydrogen sulfide concentration is greater than 0.25 grain per 100 standard cubic feet, along with the presence of carbon dioxide. *Id.*

[109] EPA, Office of Air Quality Planning and Standards, *Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas* (EPA-453/R-93-045), at ii (1993) (hereinafter "EPA Hydrogen Sulfide Report"), attached as Exhibit 54.

[110] Lana Skrtic, *Hydrogen Sulfide, Oil and Gas, and People's Health* ("Skrtic Report"), at 6 (May 2006), *available at* http://www.earthworksaction.org/pubs/hydrogensulfide_oilgas_health.pdf, attached as Exhibit 55.

[111] EPA Hydrogen Sulfide Report, *supra* n. 109, at III-35.

[112] *Id.* at ii.

[113] TSD, *supra* n.71, at 2-3.

[114] *See* James Collins & David Lewis, Report to CARB, Hydrogen Sulfide: Evaluation of Current California Air Quality Standards with Respect to Protections of Children (2000), *available at* http://oehha.ca.gov/air/pdf/oehhah2s.pdf, attached as Exhibit 56.

[115] EPA Hydrogen Sulfide Report, *supra* n. 110, at ii.

[116] *See* Pub. L. 102-187 (Dec. 4, 1991). We do not concede that this removal was appropriate. Hydrogen sulfide meets section 112 of the Clean Air Act's standards for listing as a hazardous air pollutant and should be regulated accordingly.

Although direct monitoring of hydrogen sulfide around oil and gas sources is limited, there is evidence that these emissions may be substantial, and have a serious impact on people's health. For example, North Dakota reported 3,300 violations of an odor-based hydrogen sulfide standard around drilling wells.[117] People in northwest New Mexico and western Colorado living near gas wells have long complained of strong odors, including but not limited to hydrogen sulfide's distinctive rotten egg smell. Residents have also experienced nose, throat and eye irritation, headaches, nose bleeds, and dizziness.[118] An air sample taken by a community monitor at one family's home in western Colorado in January 2011 contained levels of hydrogen sulfide concentrations 185 times higher than safe levels.[119]

Particulate Matter (PM): The oil and gas industry is a major source of PM pollution. This pollution is generated by heavy equipment used to move and level earth during well pad and road construction. Vehicles also generate fugitive dust by traveling on access roads during drilling, completion, and production activities.[120] Diesel engines used in drilling rigs and at compressor stations are also large sources of fine PM/diesel soot emissions. VOCs are also a precursor to formation of $PM_{2.5}$.[121]

PM emissions from the oil and gas industry are leading to significant pollution problems. For example, monitors in Uintah County and Duchesne County, Utah have repeatedly measured wintertime $PM_{2.5}$ concentrations above federal standards.[122] These elevated levels of $PM_{2.5}$ have been linked to oil and gas activities in the Uinta Basin.[123] Modeling also shows that road traffic associated with energy development is pushing PM_{10} levels very close to violating NAAQS standards.[124]

EPA's Air Rules Will Not Fully Address These Air Pollution Problems

Although EPA's recently finalized new source performance standards and standards for hazardous air pollutants[125] do reduce some of these pollution problems, they will not

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[117] EPA Hydrogen Sulfide Report, *supra* n. 109, at III-35.
[118] See Global Community Monitor, *Gassed! Citizen Investigation of Toxic Air Pollution from Natural Gas Development*, at 11-14 (2011), attached as Exhibit 57.
[119] *Id.* at 21.
[120] *See* BLM, GASCO Energy Inc. Uinta Basin Natural Gas Development Project Draft Environmental Impact Statement, at App. J at 2 (Oct. 2010) ("GASCO DEIS").
[121] O&G NSPS RIA, *supra* n.23, at 4-18.
[122] GASCO DEIS, *supra* n.120, at 3-12.
[123] West Tavaputs FEIS, *supra* n.41, at 3-20.
[124] *See* GASCO DEIS, *supra* n.120, at 4-27.
[125] *See* EPA, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants, 77 Fed. Reg. 49,490 (Aug. 16, 2012), *available at* http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdfl.

solve them. The rules, first, do not even address some pollutants, including NO_x, methane, and hydrogen sulfide, so any reductions of these pollutants occur only as co-benefits of the VOC reductions that the rules require.[126] Second, the rules do not control emissions from most transmission infrastructure.[127] Third, existing sources of air pollution are not controlled for any pollutant, meaning that increased use of existing infrastructure will produce emissions uncontrolled by the rules. Fourth, without full enforcement, the rules will not reduce emissions completely. Fifth, the rules will not address important emissions effects of LNG in particular, including LNG exports' tendency to increase the use of coal power. Thus, though DOE/FE might work with EPA to fully understand the emissions levels likely after the rules are fully implemented, it may not rely upon the EPA rules to avoid weighing and disclosing these impacts.

2. Gas Production Disrupts Landscapes and Habitats

Increased oil and gas production will transform the landscape of regions overlying shale gas plays, bringing industrialization to previously rural landscapes and significantly affecting ecosystems, plants, and animals. These impacts are large and difficult to manage.

Land use disturbance associated with gas development impacts plants and animals through direct habitat loss, where land is cleared for gas uses, and indirect habitat loss, where land adjacent to direct losses loses some of its important characteristics.

Regarding direct losses, land is lost through development of well pads, roads, pipeline corridors, corridors for seismic testing, and other infrastructure. The Nature Conservancy (TNC) estimated that in Pennsylvania, "[w]ell pads occupy 3.1 acres on average while the associated infrastructure (roads, water impoundments, pipelines) takes up an additional 5.7 acres, or a total of nearly 9 acres per well pad."[128] New York's Department of Environmental Conservation reached similar estimates.[129] After initial drilling is completed the well pad is partially restored, but 1 to 3 acres of the well pad will remain disturbed through the life of the wells, estimated to be 20 to 40 years.[130] Associated infrastructure such as roads and corridors will likewise remain disturbed.

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[126] *See id.* at 49,513-14.
[127] *See, e.g.*, *id.* at 49,523.
[128] TNC, Pennsylvania Energy Impacts Assessment, Report 1: Marcellus Shale Natural Gas and Wind 10, 18 (2010), attached as Exhibit 58.
[129] N.Y. Dep't of Envtl. Conservation, Revised Draft Supplemental General Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, 5-5 (2011) ("NY RDSGEIS"), available at http://www.dec.ny.gov/energy/75370.html.
[130] Id. at 6-13.

Because these disturbances involve clearing and grading of the land, directly disturbed land is no longer suitable as habitat.[131]

Indirect losses occur on land that is not directly disturbed, but where habitat characteristics are affected by direct disturbances. "Adjacent lands can also be impacted, even if they are not directly cleared. This is most notable in forest settings where clearings fragment contiguous forest patches, create new edges, and change habitat conditions for sensitive wildlife and plant species that depend on "interior" forest conditions."[132] "Research has shown measureable impacts often extend at least 330 feet (100 meters) into forest adjacent to an edge."[133]

TNC's study of the impacts of gas extraction in Pennsylvania is particularly telling. TNC mapped projected wells across the state, considering how the wells and their associated infrastructure, including roads and pipelines, interacted with the landscape. TNC's conclusions make for grim reading. It concluded:

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

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

- Nearly two thirds of well pads are projected to be in forest areas, with forest clearing projected to range between 34,000 and 83,000 acres depending on the number of number of well pads that are developed. An additional range of 80,000 to 200,000 acres of forest interior habitat impacts are projected due to new forest edges created by well pads and associated infrastructure (roads, water impoundments);

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

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

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[131] *Id.* at 6-68.
[132] Pennsylvania Energy Impacts Assessment, *supra* n.128, at 10.
[133] NY RDSGEIS, *supra* n.129, at 6-75.

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

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

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

- Marcellus gas development is projected to be extensive across Pennsylvania's 4.5 million acres of public lands, including State Parks, State Forests, and State Game Lands. Just over 10 percent of these lands are legally protected from surface development.[134]

Increased gas production will exacerbate these problems, which is bad news for the state's lands and wildlife and the hunting, angling, tourism, and forestry industries that depend on them. Although TNC adds that impacts could be reduced with proper planning,[135] more development makes mitigation more difficult. Indeed, the Pennsylvania Department of Conservation and Natural Resources recently concluded that "zero" remaining acres of the state forests are suitable for leasing with surface disturbing activities, or the forests will be significantly degraded.[136]

These land disturbance effects will harm rural economies and decrease property values, as major gas infrastructure transforms and distorts the existing landscape. They will also harm endangered species in regions where production would increase in response to Southern LNG's exports. Harm to these species and their habitat is inconsistent with the profound public interest in land and species conservation, as expressed in the Endangered Species Act and similar statutes.

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[134] Pennsylvania Energy Impacts Assessment, *supra* n.128, at 29.
[135] *See id.*
[136] Penn. Dep't of Conservation and Natural Resources, Impacts of Leasing Additional State Forest for Natural Gas Development (2011), attached as Exhibit 59.

3. Gas Production Poses Risks to Ground and Surface Water

As noted above, most of the increased production that would result from Southern LNG's proposal will likely be from shale and other unconventional gas sources, and producing gas from these sources requires hydraulic fracturing, or fracking.[137] Hydraulic fracturing involves injecting a base fluid (typically water),[138] sand or other proppant, and various fracturing chemicals into the gas-bearing formation at high pressures to fracture the rock and release additional gas. Each step of this process presents a risk to water resources. Withdrawal of the water may overtax the water source. Fracking itself may contaminate groundwater with either chemicals added to the fracturing fluid or with naturally occurring chemicals mobilized by fracking. After the well is fracked, some water will return to the surface, composed of both fracturing fluid and naturally occurring "formation" water. This water, together with drilling muds and drill cuttings, must be disposed of without further endangering water resources.

Water Withdrawals

Fracking requires large quantities of water. The precise amount of water varies by the shale formation being fracked; for example, fracking a Marcellus Shale well requires between 4 and 5 million gallons of water.[139] Fresh water constitutes 80% to 90% of the total water used to frack a well even where operators recycle "flowback" water from the fracking of previous wells for use in drilling the current one.[140]

Water withdrawals can drastically impact aquatic ecosystems and human communities. Reductions in instream flow negatively affect aquatic species by changing flow depth and velocity, raising water temperature, changing oxygen content, and altering

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[137] *See* DOE, Shale Gas Production Subcommittee First 90-Day Report, *supra* n.70, at 8.
[138] The majority of hydraulic fracturing operations are conducted with a water-based fracturing fluid. Fracking may also be conducted with oil or synthetic-oil based fluid, with foam, or with gas.
[139] Pennsylvania Energy Impacts Assessment, *supra* n.128, at 5. *Accord* NY RDSGEIS, *supra* n.129, at 6-10 ("Between July 2008 and February 2011, average water usage for high-volume hydraulic fracturing within the Susquehanna River Basin in Pennsylvania was 4.2 million gallons per well, based on data for 553 wells."). Other estimates suggest that as much as 7.2 million gallons of frack fluid may be used in a 4000 foot well bore. NRDC, *et al.*, *Comment on NY RDSGEIS on the Oil, Gas and Solution Mining Regulatory Program* (Jan. 11, 2012) (Attachment 2, Report of Tom Myers, at 10), attached as Exhibit 60 ("Comment on NY RDSGEIS"). Water needs in other geological formations vary. *See* DOE, Shale Gas Production Subcommittee First 90-Day Report, *supra* n.70, at 19 (estimating that, nationwide, fracking an individual well requires between 1 and 5 million gallons of water).
[140] NY RDSGEIS, *supra* n.129, at 6-13.

streambed morphology.[141] Even when flow reductions are not themselves problematic, the intake structures can harm aquatic organisms.[142] Where water is withdrawn from aquifers, rather than surface sources, withdrawal may cause permanent depletion of the source. This risk is even more prevalent with withdrawals for fracking than it is for other withdrawal, because fracking is a consumptive use. Fluid injected during the fracking process is (barring accident) deposited below freshwater aquifers and into sealed formations.[143] Thus, the water withdrawn from the aquifer will be used in a way that provides no opportunity to percolate back down to the aquifer and recharge it.

Groundwater Contamination

Fracturing poses a serious risk of groundwater contamination. Contaminants include chemicals added to the fracturing fluid and naturally occurring chemicals that are mobilized from deeper formations to groundwater via the fracking process. Contamination may occur through several methods, including where the well casing fails or where the fractures created through drilling intersect an existing, poorly sealed well. Although information on groundwater contamination is incomplete, the available research indicates that contamination has already occurred on multiple occasions.

One category of potential contaminants includes chemicals added to the drilling mud and fracturing fluid. The fluid used for slickwater fracturing is typically comprised of more than 98% fresh water and sand, with chemical additives comprising 2% or less of the fluid.[144] Chemicals are added as solvents, surfactants, friction reducers, gelling agents, bactericides, and for other purposes.[145] New York recently identified 322 unique ingredients used in fluid additives, recognizing that this constituted a partial list.[146] These chemicals include petroleum distillates; aromatic hydrocarbons; glycols; glycol ethers; alcohols and aldehydes; amides; amines; organic acids, salts, esters and related chemicals; microbicides; and others. Many of these chemicals present health risks.[147] Of particular note is the use of diesel, which the DOE Subcommittee has singled out for its harmful effects and recommended be banned from use as a fracturing fluid additive.[148] The minority staff of the House Committee on Energy and Commerce has determined that, despite diesel's risks, between 2005 and 2009 "oil and gas service

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[141] *Id.* at 6-3 to 6-4.
[142] *Id.* at 6-4.
[143] *Id.* at 6-5; First 90-Day Report, *supra* n.70, at 19 ("[I]n some regions and localities there are significant concerns about consumptive water use for shale gas development.").
[144] NY RDSGEIS, *supra* n.129, at 5-40.
[145] *Id.* at 5-49.
[146] *Id.* at 5-41.
[147] *Id.* at 5-75 to 5-78.
[148] DOE, Shale Gas Production Subcommittee First 90-Day Report, *supra* n.70, at 25.

companies injected 32.2 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 19 states."[149]

Contamination may also result from chemicals naturally occurring in the formation. Flowback and produced water "may include brine, gases (e.g. methane, ethane), trace metals, naturally occurring radioactive elements (e.g. radium, uranium) and organic compounds."[150] For example, mercury naturally occurring in the formation becomes mixed in with water-based drilling muds, resulting in up to 5 pounds of mercury in the mud per well drilled in the Marcellus region.[151]

There are several vectors by which these chemicals can reach groundwater supplies. Perhaps the most common or significant are inadequacies in the casing of the vertical well bore.[152] The well bore inevitably passes through geological strata containing groundwater, and therefore provides a conduit by which chemicals injected into the well or traveling from the target formation to the surface may reach groundwater. The well casing isolates the groundwater from intermediate strata and the target formation. This casing must be strong enough to withstand the pressures of the fracturing process—the very purpose of which is to shatter rock. Multiple layers of steel casing must be used, each pressure tested before use, then centered within the well bore. Each layer of casing must be cemented, with careful testing to ensure the integrity of the cementing.[153]

Separate from casing failure, contamination may occur when the zone of fractured rock intersects an abandoned and poorly-sealed well or natural conduit in the rock.[154] One recent study concluded, on the basis of geologic modeling, that frack fluid may migrate from the hydraulic fracture zone to freshwater aquifers in less than ten years.[155]

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[149] Natural Resources Defense Council, Earthjustice, and Sierra Club, Comments [to EPA] on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels 3, (June 29, 2011) (quoting Letter from Reps. Waxman, Markey, and DeGette to EPA Administrator Lisa Jackson 1 (Jan. 31, 2001)) ("Comment on Diesel Guidance"), attached as Exhibit 61.
[150] E, Shale Gas Production Subcommittee First 90-Day Report, *supra* n.70, at 21; *see also* Comment on NY RDSGEIS, *supra* n.139, attachment 3, Report of Glen Miller, at 2.
[151] Comment on NY RDSGEIS, *supra* n.139, attachment 1, Report of Susan Harvey, at 92.
[152] DOE, Shale Gas Production Subcommittee First 90-Day Report, *supra* n.70, at 20.
[153] Comment on Diesel Guidance, *supra* n.149, at 5-9.
[154] Comment on NY RDSGEIS, *supra* n.139, attachment 3, Report of Tom Myers, at 12-15.
[155] Tom Myers, *Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers* (Apr. 17, 2012), attached as Exhibit 62.

Available empirical data indicates that fracking has resulting in groundwater contamination in at least five documented instances. One study "documented the higher concentration of methane originating in shale gas deposits . . . into wells surrounding a producing shale production site in northern Pennsylvania."[156] By tracking certain isotopes of methane, this study – which the DOE Subcommittee referred to as "a recent, credible, peer-reviewed study" determined that the methane originated in the shale deposit, rather than from a shallower source.[157] Two other reports "have documented or suggested the movement of fracking fluid from the target formation to water wells linked to fracking in wells."[158] "Thyne (2008)[[159]] had found bromide in wells 100s of feet above the fracked zone. The EPA (1987)[[160]] documented fracking fluid moving into a 416-foot deep water well in West Virginia; the gas well was less than 1000 feet horizontally from the water well, but the report does not indicate the gas-bearing formation."[161]

More recently, EPA has investigated groundwater contamination in Pavillion, Wyoming and Dimock, Pennsylvania. In the Pavillion investigation, EPA's draft report concludes that "when considered together with other lines of evidence, the data indicates likely impact to ground water that can be explained by hydraulic fracturing."[162] EPA tested water from wells extending to various depths within the range of local groundwater. At the deeper tested wells, EPA discovered inorganics (potassium, chloride), synthetic organic (isopropanol, glycols, and tert-butyl alcohol), and organics (BTEX, gasoline and diesel range organics) at levels higher than expected.[163] At shallower levels, EPA

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[156] DOE, Shale Gas Production Subcommittee First 90-Day Report, *supra* n.70, at 20 (citing Stephen G. Osborn, Avner Vengosh, Nathaniel R. Warner, and Robert B. Jackson, Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing, Proceedings of the National Academy of Science, 108, 8172-8176, (2011)).
[157] *Id.*
[158] Comment on NY RDSGEIS, *supra* n.139, attachment 3, Report of Tom Myers, at 13.
[159] Dr. Myers relied on Geoffrey Thyne, *Review of Phase II Hydrogeologic Study* (2008), prepared for Garfield County, Colorado, *available at* http://cogcc.state.co.us/Library/Presentations/Glenwood_Spgs_HearingJuly_2009/(1_A)_ReviewofPhase-II-HydrogeologicStudy.pdf.
[160] EnvironmentalProtection Agency, Report to Congress, Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy, vol. 1 (1987), *available at* nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=20012D4P.txt, attached as Exhibit 63.
[161] Comment on NY RDSGEIS, *supra* n.139, attachment 3, Report of Tom Myers, at 13.
[162] EPA, Draft Investigation of Ground Water Contamination near Pavillion, Wyoming, at xiii (2011), available at http://www.epa.gov/region8/superfund/wy/pavillion/EPA_ReportOnPavillion_Dec-8-2011.pdf, attached as Exhibit 64.
[163] *Id.* at xii.

detected "high concentrations of benzene, xylenes, gasoline range organics, diesel range organics, and total purgeable hydrocarbons."[164] EPA determined that surface pits previously used for storage of drilling wastes and produced/flowback waters were a likely source of contamination for the shallower waters, and that fracturing likely explained the deeper contamination.[165] Although this is a draft report in an ongoing investigation, an independent expert who reviewed the EPA Pavillon study at the request of Sierra Club and other environmental groups has supported EPA's findings.[166]

EPA is also investigating groundwater contamination in Dimock, Pennsylvania.[167] In Dimock, EPA has determined that "a number of home wells in the Dimock area contain hazardous substances, some of which are not naturally found in the environment."[168] Specifically, wells are contaminated with arsenic, barium, bis(2(ethylhexyl)phthalate, glycol compounds, manganese, phenol, and sodium.[169] Many of these chemicals are hazardous substances as defined under CERCLA section 101(14). *See* 42 U.S.C. § 9604(a); 40 C.F.R. § 302.4. EPA's determination is based on "Pennsylvania Department of Environmental Protection (PADEP) and Cabot Oil and Gas Corporation (Cabot) sampling information, consultation with an EPA toxicologist, the Agency for Toxic Substances and Disease Registry (ATSDR) Record of Activity (AROA), issued, 12/28/11, and [a] recent EPA well survey effort."[170] The PADEP information provided reason to believe that drilling activities in the area led to contamination of these water supplies. Drilling in the area began in 2008, and was conducted using the hazardous substances that have since been discovered in well water. Shortly thereafter methane contamination was detected in private well water. The drilling also caused several surface spills. After the contamination was detected, PADEP entered into a consent agreement with Cabot which required permanent restoration or replacement of the

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164 *Id.* at xi.
165 *Id.* at xi, xiii.
166 Tom Myers, *Review of DRAFT: Investigation of Ground Water Contamination near Pavillion Wyoming* (April 30, 2012), available at http://docs.nrdc.org/energy/files/ene_12050101a.pdf, attached as Exhibit 65.
167 EPA Region III, Action Memorandum - Request for Funding for a Removal Action at the Dimock Residential Groundwater Site (Jan. 19, 2012), available at http://www.epaosc.org/sites/7555/files/Dimock%20Action%20Memo%2001-19-12.PDF, attached as Exhibit 66,
168 *Id.* at 1.
169 *Id.* at 3-4.
170 *Id.* at 1.

water supply.[171] Cabot has installed or is installing a "gas mitigation" system for the affected wells.[172]

Pursuant to the consent decree, Cabot was providing replacement water to all 18 homes covered by the consent agreement until November 30, 2011, at which point Cabot halted delivery with PADEP's consent.[173] EPA has intervened because "EPA does not know what, if any, hazardous substances these 'gas mitigation' systems, originally designed to address methane, are removing."[174] EPA sampled water from 64 home wells and found hazardous substances, specifically arsenic, barium or manganese, all of which are also naturally occurring substances, in well water at five homes at levels that could present a health concern. In all cases the residents have now or will have their own treatment systems that can reduce concentrations of those hazardous substances to acceptable levels at the tap." [175]

The serious groundwater contamination problems experienced at the Pavillion and Dimock sites demonstrate a possibility of contamination, and attendant human health risks, that DOE must consider in its public interest evaluation.

Waste Management

Fracturing produces a variety of liquid and solid wastes that must be managed and disposed of. These include the drilling mud used to lubricate the drilling process, the drill cuttings removed from the well bore, the "flowback" of fracturing fluid that returns to the surface in the days after fracking, and produced water that is produced over the life of the well (a mixture of water naturally occurring in the shale formation and lingering fracturing fluid). Because these wastes contain the same contaminants described in the preceding section, environmental hazards can arise from their management and ultimate disposal.

On site, drilling mud, drill cuttings, flowback and produced water are often stored in pits. Open pits can have harmful air emissions, can leach into shallow groundwater, and can fail and result in surface discharges. Many of these harms can be minimized by the

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[171] *Id.* at 1-2.

[172] *See* Agency for Toxic Substances and Disease Registry, Record of Activity/Technical Assist (Dec. 28, 2011) at 2 ("ATSDR"), available at http://www.epa.gov/aboutepa/states/dimock-atsdr.pdf, attached as Exhibit 67.

[173] *Id.* at 2.

[174] EPA Action Memorandum, *supra* n.167, at 2.

[175] EPA, *EPA Completes Drinking Water Sampling in Dimock, Pa* (July 25, 2012), available at http://yosemite.epa.gov/opa/admpress.nsf/0/1A6E49D193E1007585257A46005B61AD, attached as Exhibit 68.

use of seal tanks in a “closed loop” system.[176] Presently, only New Mexico mandates the use of closed loop waste management systems, and pits remain in use elsewhere.

Flowback and produced water must ultimately be disposed of offsite. Some of these fluids may be recycled and used in further fracturing operations, but even where a fluid recycling program is used, recycling leaves concentrated contaminants that must be disposed of. The most common methods of disposal are disposal in underground injection wells or through water treatment facilities leading to eventual surface discharge.

Underground injection wells present risks of groundwater contamination similar to those identified above for fracking itself. Gas production wastes are not categorized as hazardous under the Safe Drinking Water Act, 42 U.S.C. § 300f *et seq.*, and may be disposed of in Class II injection wells. Class II wells are brine wells, and the standards and safeguards in place for these wells were not designed with the contaminants found in fracking wastes in mind.[177]

Additionally, underground injection of fracking wastes appears to have induced earthquakes in several regions. For example, underground injection of fracking waste in Ohio has been correlated with earthquakes as high as 4.0 on the Richter scale.[178] Underground injection may cause earthquakes by causing movement on existing fault lines: “Once fluid enters a preexisting fault, it can pressurize the rocks enough to move; the more stress placed on the rock formation, the more powerful the earthquake.”[179] Underground injection is more likely than fracking to trigger large earthquakes via this mechanism “because more fluid is usually being pumped underground at a site for longer periods.”[180] In light of the apparent induced seismicity, Ohio has put a moratorium on injection in the affected region. Similar associations between earthquakes and injection have occurred in Arkansas, Texas, Oklahoma and the United

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[176] *See, e.g.,* NY RDSGEIS, *supra* n.139, at 1-12.
[177] *See* NRDC et al., Petition for Rulemaking Pursuant to Section 6974(a) of the Resource Conservation and Recovery Act Concerning the Regulation of Wastes Associated with the Exploration, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy (Sept. 8, 2010), attached as Exhibit 69.
[178] Columbia University, Lamont-Doherty Earth Observatory, Ohio Quakes Probably Triggered by Waste Disposal Well, Say Seismologists (Jan. 6, 2012), available at http://www.ldeo.columbia.edu/news-events/seismologists-link-ohio-earthquakes-waste-disposal-wells, attached as Exhibit 70.
[179] *Id.*
[180] *Id.*

Kingdom.[181] In light of these effects, Ohio and Arkansas have placed moratoriums on injection in the affected areas.[182] The recently released abstract of a forthcoming United States Geological Survey study affirms the connection between disposal wells and earthquakes.[183]

As an alternative to underground injection, flowback and produced water is also sent to water treatment facilities, leading to eventual surface discharge. This presents a separate set of environmental hazards, because these facilities (particularly publicly owned treatment works) are not designed to handle the nontraditional pollutants found in fracking wastes. For example:

> One serious problem with the proposed discharge (dilution) of fracture treatment wastewater via a municipal or privately owned treatment plant is the observed increases in trihalomethane (THM) concentrations in drinking water reported in the public media (Frazier and Murray, 2011), due to the presence of increased bromide concentrations. Bromide is more reactive than chloride in formation of trihalomethanes, and even though bromide concentrations are generally lower than chloride concentrations, the increased reactivity of bromide generates increased amounts of bromodichloromethane and dibromochloromethane (Chowdhury, et al., 2010). Continued violations of an 80microgram/L THM standard may ultimately require a drinking water treatment plant to convert from a standard and cost effective chlorination disinfection treatment to a more expensive chloramines process for water treatment. Although there are many factors affecting THM production in a specific water, simple (and cheap) dilution of fracture treatment water in

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[181] *Id.*; *see also* Alexis Flynn, Study Ties Fracking to Quakes in England, Wall Street Journal (Nov. 3, 2011), *available at* http://online.wsj.com/article/SB10001424052970203804204577013771109580352.html, attached as Exhibit 71.
[182] Lamont-Doherty Earth Observatory; Arkansas Oil and Gas Commission, Class II Commercial Disposal Well or Class II Disposal Well Moratorium (Aug. 2, 2011), *available at* http://www.aogc.state.ar.us/Hearing%20Orders/2011/July/180A-2-2011-07.pdf, attached as Exhibit 72.
[183] Ellsworth, W. L., et al., Are Seismicity Rate Changes in the Midcontinent Natural or Manmade?, Seismological Society of America, (April 2012), available at http://www2.seismosoc.org/FMPro?-db=Abstract_Submission_12&-recid=224&-format=%2Fmeetings%2F2012%2Fabstracts%2Fsessionabstractdetail.html&-lay=MtgList&-find, attached as Exhibit 73.

> a stream can result in a more expensive treatment for disinfection of drinking water. This transfer of costs to the public should not be permitted.[184]

Similarly, municipal treatment works typically to not treat for radioactivity, whereas produced water can have high levels of naturally occurring radioactive materials. In one examination of three samples of produced water, radioactivity (measured as gross alpha radiation) were found ranging from 18,000 pCi / L to 123,000 pCi/L, whereas the safe drinking water standard is 15 pCi/L.[185]

c. Other Nationwide and Global Impacts

i. Price Increases

Natural gas exports will increase domestic gas prices. There is a broad consensus on this issue, which Southern LNG does not dispute. On three particulars, however, Southern LNG makes arguments that DOE/FE must reject. First, DOE/FE must consider the cumulative price impacts of all pending export proposals, rejecting Southern LNG's suggestion that its exports be considered in isolation. Second, price forecasts must reflect EIA's most recent prediction of U.S. gas reserves, as well as the inherent uncertainty surrounding gas production. Third, Southern LNG's assertion that exports will reduce volatility in gas prices is unsupported.

Beginning with price impacts, DOE must consider the cumulative effects of all pending proposals, rather than looking solely at the impact attributable to Southern LNG's proposed exports. The public, after all, will not experience each proposed terminal as an individual project: It will experience them cumulatively, through the gas and electricity prices that they will raise and the environmental damage that they will cause.[186] Because prices increase non-linearly with exports, effects of individual proposals cannot be considered in isolation. That is, going from 4 to 6 bcf/d in exports impacts domestic

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184 Comment on NY RDSGEIS, *supra* n.139, attachment 3, Report of Glen Miller, at 13.
185 *Id.* at 4.
186 Nonetheless, even if DOE/FE were to unlawfully look solely to effects attributable to Southern LNG, DOE/FE would have to conclude that these impacts were significant. Southern LNG, relying on a report from Navigant Consulting, concludes that its proposed 0.5 bcf/d of exports would increase hub prices by 11 cents per mmbtu in 2016, rising to 21 cents by 2035 (2.9% and 3.3% higher than Navigant's "baseline" scenarios, respectively). App. at appx. A p. 3. Similarly, NERA concluded that the price impacts of only 0.5 bcf/d (0.18 tcf/year) will adversely impact employment in manufacturing and energy intensive industries. NERA report, *supra* n.17, at 38, 60-61. *See also* part III.C.2, below.

prices more than going from 0 to 2 bcf/d.[187] One reason for this is that domestic gas consumers differ in their ability to reduce gas consumption.[188] As export volumes increase, increasing numbers of inflexible domestic consumers are forced to compete with exports, further driving up prices. When export volumes are lower, by contrast, even small price increases will lead price-sensitive domestic consumers to reduce their consumption, freeing gas supplies for exports and limiting price impacts.[189]

Given these dynamics, it is crucial that DOE/FE consider the impact of the full volume of proposed exports. Presently, proposals for 27.58 bcf/d of exports are pending before DOE/FE.[190] For perspective, note that 27.58 bcf/d is over 36% of current domestic gas production.[191] The Navigant study Southern LNG submits considers only a small fraction of these. Even Navigant's "aggregate" export case only considers the marginal effect of 4.0 bcf/d of exports, less than 15% of the total.[192] The *EIA Export Study* also considers less than half of the total volume of proposed export, considering scenarios in which 6

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[187] Robert Brooks, *Using GPCM to Model LNG Exports from the US Gulf Coast* 5 (2012), available at http://www.rbac.com/press/LNG%20Exports%20from%20the%20US.pdf, attached as Exhibit 74.
[188] *Id.* at 7.
[189] Estimates of exports' price impacts differ in their assumption of price sensitivity of domestic consumers. One study that estimates low price-sensitivity predicts significantly higher price increases than either Navigant or the EIA study. *Id.* at 5, 7.
[190] Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of October 16, 2012), available at http://fossil.energy.gov/programs/gasregulation/reports/Long_Term_LNG_Export_10-16-12.pdf and attached as Exhibit 75.
[191] EIA, Monthly Natural Gas Gross Production Report (November 2, 2012), available at http://www.eia.gov/oil_gas/natural_gas/data_publications/eia914/eia914.html, attached as Exhibit 76. This report states that, for the month of August 2012, gross U.S. withdrawals (not limited to the lower 48) were 76.60 bcf/d. The highest monthly production in the past 12 months was 83.06 bcf/d in January 2012; the currently pending proposed exports amount to over 33% of this total.
[192] Application Appendix A at 40. Although Navigant also acknowledges 2.2 bcf/d of proposed exports from Sabine Pass, Lousiana and 1.5 bcf/d proposed exports from Kitimat, British Columbia, Navigant wrongly includes these totals in its "baseline" scenario, and therefore does not consider the marginal effect of adding these exports. *Id.* These potential exports should be considered, but should not be included in the baseline because Sabine Pass, for example, has not yet received final DOE/FE approval, as DOE/FE is currently considering Sierra Club's petition for reconsideration of Sabine Pass's export authorization. As such, when considering the aggregate effect of exports on domestic gas prices, DOE/FE must use the baseline in which no LNG exports occur from the U.S.

or 12 bcf/d of gas are exported, with exports phased in either slowly or quickly.[193] Similarly, although the recent NERA report considered higher volumes of exports in certain limited scenarios,[194] this report did not consider the effect of the full volume of proposed exports, and as explained below, NERA's unwarranted assumptions about the cost of liquefying and transporting natural gas led it to understate the possibility of exports in low production scenarios. Adjusting these reports to account for the full volume of export proposals will significantly increase the predicted price impact.

Consideration of the full volume of proposed exports is not only the prudent means of fully evaluating the decisions before DOE/FE, but is also a required component of DOE/FE's NEPA and public interest analyses. DOE/FE cannot authorize a proposed project on the assumption that the project will never be placed into operation. Under NEPA, an agency may only exclude analysis of an event and its consequences when the event "is so 'remote and speculative' as to reduce the effective probability of its occurrence to zero." *See New York v. NRC*, 681 F.3d 471, 482 (D.C. Cir. 2012); *see also San Luis Obispo Mothers for Peace v. Nuclear Regulatory Comm'n*, 449 F.3d 1016, 1031 (9th Cir. 2006) (same). Here, DOE/FE cannot rule out as speculative the possibility of all proposed exports occurring.

Although the NERA report concluded that only a portion of the proposed exports were likely to occur, several assumptions underlying the NERA report lead it to understate the likelihood of exports. For example, NERA assumes that only the optimal number of export terminals will be built, and incorporates the capital costs of these terminals into its predictions of the per-MMbtu price of providing liquefaction services.[195] Thus, NERA ignores the possibility that excess domestic liquefaction capacity will be built. In practice, decisions to build liquefaction facilities are being made in the short term, and project proponents indicate that many of these facilities will in fact be built. Once costs are sunk into these facilities, over-capacity may lead domestic terminals to provide liquefaction at a discount in an effort to recover sunk costs, thereby lowering the overall price importers must pay for US sourced LNG, and thereby increasing the amount of gas exported. NERA also ignores the alternative possibility that long-term contracts at export terminals will lock in exports regardless of subsequent domestic price increases. Similarly, NERA overstates potentially the transportation cost associated with export of US gas by assuming that all US gas will be exported from the Gulf Coast.[196] Exports from the Gulf Coast to Asia have high transportation costs, raising prices paid by the importer and thus disincentivizing exports. Several export terminals are proposed for the West Coast, however, and these terminals will have lower transportation costs to Asia. As

[193] *EIA Export Study*, *supra* n.13, at 1.
[194] NERA report, *supra* n.17, at 40. Aside from considering different volumes of exports, NERA's predictions of price impacts are designed to track EIA's. *Id.* at 200.
[195] NERA, *supra* n.17, at 57, 85.
[196] NERA, *supra* n.17, at 88-89, 210.

such, completion of these terminals may lead to higher volumes of exports than NERA predicts.

In summary, to determine whether any one export proposal is consistent with the public interest, DOE/FE must consider not only the effect of the particular proposal, but the effect of that proposal in conjunction with all proposals so far approved and all reasonably foreseeable future proposals. Moreover, this analysis must examine the possibility that all proposals that receive approval will export to the fully authorized extent. Obviously, the most efficient way to consider this question is through programmatic studies, including a programmatic EIS as we recommend above and similar to the reports DOE/FE has already commissioned from EIA and NERA. For the reasons explained above, however, the existing EIA and NERA studies fail to examine the full amount of proposed exports and the full potential of exports' price impacts. Before DOE/FE approves any of the pending flood of export proposals, DOE/FE must develop a clear picture of what the ultimate price impacts may be, and a justification as to why, if these price impacts will cause the harms described below, approval is nonetheless in the public interest.

The second problem with Southern LNG's price arguments is that Southern LNG and Navigant overstate domestic supply. EIA has recently drastically reduced its estimates of total gas supplies. EIA's 2011 Annual Energy Outlook assumed total domestic reserves of 827 tcf of natural gas. The more recent 2012 Annual Energy Outlook cuts the estimates of reserves by over 40%, to 482 tcf.[197] Navigant acknowledges this change, but declines to use EIA's most recent figures, instead noting that some other sources have criticized EIA's reduced estimate. App. at appx. A pp. 6, 12. Nothing in the record, however, would permit DOE/FE to disregard this lower estimate, produced by the federal agency charged with developing expertise in these matters. And EIA's prior export study demonstrates that the price impacts of exports are highly dependent on gas recovery and, by extension, the size of the domestic gas supply. The *EIA Export Study* evaluated various export regimes in the contexts of four background scenarios: the EIA's Annual Energy Outlook ("AEO") 2011 reference case, cases where shale recoveries were 50% higher or lower than in the reference case, and a high economic growth reference case. *Id.* Price impacts are dramatically higher when gas recoveries are lower.[198] Even the *EIA Export Study*'s predictions of price impacts are too low, because the *EIA Export Study* also uses the now-outdated 2011 Annual Energy Outlook estimate of recoverable gas reserves and because the EIA did not account for the full volume of proposed exports. Thus, Southern LNG's discussion of gas supply is flawed in two regards: it disregards the most recent and authoritative estimate of total supply, and unlike the EIA's analysis, it fails to account for uncertainty in gas supply by providing predictions for low ultimate recovery scenarios.

[197] EIA 2012 Annual Energy Outlook at 9, 13, *see also* Exhibit 76.
[198] EIA Export Study Figure, *supra* n.13, at Fig. 4 and tables& tbls. B3 and& B4.

Third and finally, DOE/FE must reject Southern LNG's assertion that the demand provided by exports will provided a needed decrease in domestic gas price volatility. As the Navigant report provided by Southern LNG acknowledges, historic gas price volatility resulted from the high capital expenditure and uncertainty involved in conventional gas production. App. at appx. A p.9. Because it was difficult to predict whether a conventional well would be an unproductive "dry hole," for example, producers would stop exploration and development of new resources when gas prices were low, and production was slow to resume when gas prices climbed, resulting in high volatility.[199] As Navigant itself explains, unconventional production is much more predictable. App. at appx. A p.9. Because producers face less uncertainty, they need not wait for a drastic swing in prices to resume or expand production. Southern LNG offers no evidence from which DOE/FE could conclude that volatility would persist despite this significant change in the dynamics of domestic gas production, nor does Southern LNG provide evidence sufficient to show that, if volatility did persist, demand from any volume of exports would meaningfully affect this volatility. Southern LNG and Navigant's passing assertions of an effect on volatility[200] must be rejected.

ii. Changes in Domestic Power Production

Southern LNG's export proposal will further increase air pollution by increasing the amount of coal used for domestic electricity production. The EIA Export Study predicts that exports, by causing natural gas prices to rise, will drive more electricity generation to coal than to renewable energy. According to the EIA, the power sector will "primarily" respond to higher natural gas prices by shifting to coal-fired generation, and only secondarily to renewable sources.[201] Specifically, EIA predicts that 72 percent of the decrease in gas-fired electricity production will be replaced by coal-fired production, with increased liquid fuel consumption, increased renewable generation, and decreases in total consumption making up the remainder (8, 9, and 11 percent, respectively).[202]

The shift from gas- to coal-fired electricity generation will increase emissions of both traditional air pollutants and greenhouse gases. Gas-fired power plants generate less than a third of the nitrogen oxides and one percent of the sulfur oxides that coal-fired

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[199] *Id.*
[200] *Id.*, *see also* Application Appendix B at 48.
[201] EIA Export Study, *supra* n.13, at 6; *see also id.* at 17 ("[H]igher natural gas prices lead electric generators to burn more coal and less natural gas.").
[202] *Id.* at 18.

plants generate.[203] Thus, the EIA Export Study demonstrates that exports will harm the local environment by causing the opposite shift here.[204]

Coal-fired plants also release roughly twice the carbon dioxide combustion emissions as gas-fired plants, although, as discussed in the following section, some of this combustion advantage is offset by the greenhouse gas emissions resulting from gas production. Accordingly, the price increase and corresponding shift to coal-fired power generation risks increasing greenhouse gas pollution. The *EIA Export Study* examined the effects of 6 or 12 bcf/d of exports, phased in slowly or quickly, together with various estimates for the extent of shale gas reserves and the pace of US economic development. EIA concluded that under every scenario exports would produce a significant increase in domestic greenhouse gas emissions, as illustrated by the table below.

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203 EPA, Air Emissions, http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html (last visited Dec. 12, 2012), attached as Exhibit 77.

204 The macroeconomic study DOE/FE recently commissioned from NERA Economic Consulting did not examine shifts within the domestic power sector in detail. Moreover, although the NERA study found that exports prompted a lower change in demand for natural gas in the electricity sector than the change the EIA study predicted, the NERA study authors admitted that their model, unlike EIA's NEMS model, is ill suited to modeling changes in electricity sector demand for gas relative to other fuels. The NERA study states: "[T]he NERA results show much greater demand response in the industrial sector [than the EIA results] while at the same time much less demand response in the electricity sector. These differences appear to be consistent across all baseline cases. The main reason for the variations in the electricity sector comes from the different way that the sector is modeled. EIA's NEMS model has a detailed bottom-up representation of the electricity sector, while the electricity sector in the NERA model is a nested CES function with limited technologies. This means that NEMS allows for switching from natural gas-based generation to other technology types easily, while the possibility of switching out of natural gas is more limited and controlled in the NERA model." NERA Study, *supra* n.17, at 207 (appx. D, figs. 176-78 and accompanying text). Because the EIA model is better suited to predicting domestic power impacts, DOE/FE should accord greatest weight to the EIA results related to fuel-switching.

Table 1: Cumulative CO_2 Emissions from 2015 to 2035 With Various Export Scenarios[205]

Case	no added exports	low/slow	low/rapid	high/slow	high/rapid
Reference					
Cumulative carbon dioxide emissions	125,056	125,699	125,707	126,038	126,283
Change from baseline		643	651	982	1,227
Percentage change from baseline		0.5%	0.5%	0.8%	1.0%
High Shale EUR					
Cumulative carbon dioxide emissions	124,230	124,888	124,883	125,531	125,817
Change from baseline		658	653	1,301	1,587
Percentage change from baseline		0.5%	0.5%	1.0%	1.3%
Low Shale EUR					
Cumulative carbon dioxide emissions	125,162	125,606	125,556	125,497	125,670
Change from baseline		444	394	335	508
Percentage change from baseline		0.4%	0.3%	0.3%	0.4%
High Economic Growth					
Cumulative carbon dioxide emissions	131,675	131,862	132,016	131,957	132,095
Change from baseline		187	341	282	420
Percentage change from baseline		0.1%	0.3%	0.2%	0.3%

Source: U.S. Energy Information Administration, National Energy Modeling System, with emissions related to natural gas assumed to be consumed in the liquefaction process included.

The fact that gas exports will tend to favor coal as a fuel for domestic electrical generation has particularly important implications for national emissions control efforts. EPA has just released proposed carbon pollution standards for electricity generating units which set emissions levels based upon the performance of natural gas combined-cycle plants.[206] EPA anticipates no notable compliance costs for the rule because it expects utilities to react to low gas prices, among other factors, by avoiding constructing expensive coal-fired plants.[207] If LNG exports move forward, however, gas prices will increase, making it more difficult and expensive to capture combustion-side carbon pollution reductions from fossil-fuel fired power plants. This interference with national efforts to control global warming, which endangers public health and welfare,[208] is not in the public interest.

[205] From the *EIA Export Study*, *supra* n.13, at 19.
[206] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed. Reg. 22,392 (Apr. 13, 2012).
[207] *See id.* at 22,430.
[208] *See* Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496 (Dec. 15, 2009).

iii. Effects on Global Greenhouse Gas Emissions

Several other export applicants have argued that LNG exports will benefit the environment by allowing importing countries to burn natural gas in place of coal, fuel oil, or other fuels with higher carbon intensities, and that LNG exports will thereby reduce global greenhouse gas emissions. This argument is wrong for two reasons.

First, looking at importing countries' response to exports, a recent study by the International Energy Agency predicts that international trade in LNG and other measures to increase global availability of natural gas will lead many countries to use natural gas in place of wind, solar, or other renewables, displacing these more environmentally beneficial energy sources instead of displacing other fossil fuels, and that these countries may also increase their overall energy consumption beyond the level that would occur with exports.[209] In the United States alone, the IEA expects the gas boom to result in a 10% reduction in renewables relative to a baseline world without increased gas use and trade.[210] The IEA goes on to conclude that high levels of gas production and trade will produce "only a small net shift" in global greenhouse gas emissions, with atmospheric CO_2 levels stabilizing at over 650 ppm and global warming in excess of 3.5 degrees Celsius, "well above the widely accepted 2°C target."[211] Another recent study, prepared by the Joint Institute for Strategic Energy Analysis (JISEA), also modeled power sector futures resulting from increasing U.S. reliance on natural gas.[212] That study likewise found that, under baseline assumptions for future electricity demand and policy measures, "natural gas and coal swap positions compared to their historical levels," with wind energy growing at a rate that represents "a significant reduction from deployment in recent years;" as a result, CO2 emissions "do not begin to transition to a trajectory that many scientists believe is necessary to avoid dangerous impacts from climate change."[213]

Second, even where importing countries do substitute gas for coal or fuel oil, the available evidence indicates that this substitution is likely to cause little, if any, reduction in global greenhouse gas emissions. LNG production imposes significant environmental and energy costs beyond those associated with the production of non-

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[209] International Energy Agency, *Golden Rules for a Golden Age of Gas*, Ch. 2 p. 91 (2012), available at http://www.iea.org/publications/freepublications/publication/WEO2012_GoldenRulesReport.pdf, attached as Exhibit 78.

[210] *Id.* at 80.

[211] *Id.*

[212] Jeffrey Logan et al., Joint Inst. for Strategic Analysis, Natural Gas and the Transformation of the U.S. Energy Sector (2012), *available at* http://www.nrel.gov/docs/fy13osti/55538.pdf, attached as Exhibit 79.

[213] *Id.* at 98.

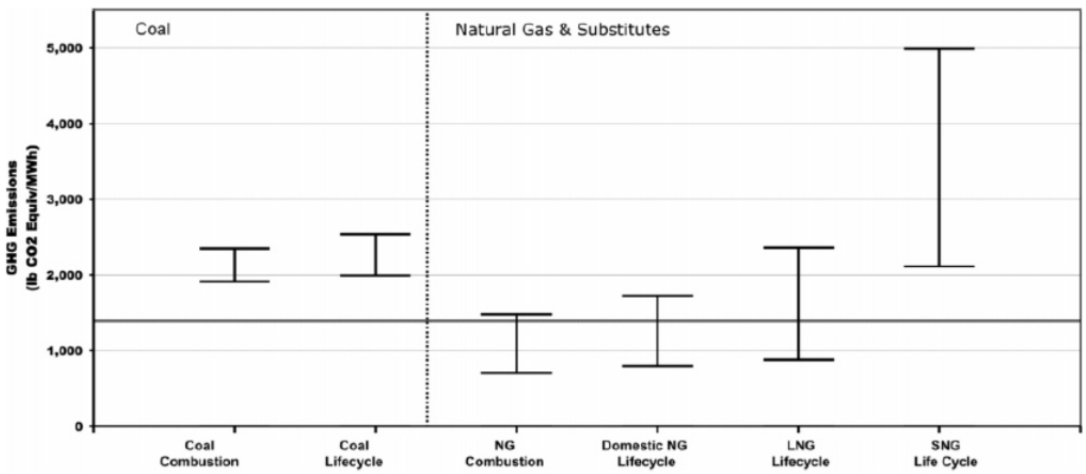
liquefied gas. Liquefying natural gas is an energy intensive process. Additional energy is then consumed in the transportation of the gas, with attendant greenhouse gas emissions. Finally, the LNG must be regasified at the import terminal, often through the use of heat generated by the burning of yet more natural gas. These operations drastically increase the lifecycle greenhouse gas emissions of LNG, adding between 13.85 and 51.7 pounds of CO_2e per MMBtu.[214]

Emissions from liquefaction, transportation and gasification mean that the greenhouse gas emissions associated with LNG are significantly higher than those associated with domestic natural gas. For perspective, natural gas *combustion* emits roughly 120 pounds of CO_2e per MMBtu.[215] Using the above conservative figures, the process of liquefying, transporting, and regasifying LNG accordingly emits 19% to 23% of the CO_2e emitted by natural gas combustion itself—a substantial increase. Jaramillo 2007 concluded that this increase could bring LNG's lifecycle greenhouse gas emissions into parity with coal:

[214] Paulina Jaramillo, W. Michael Griffin, H. Scott Matthews, Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation, 41 Environ. Sci. Technol. 6,290 (2007) ("Jaramillo 2007"), *available at* http://www.ce.cmu.edu/~gdrg/readings/2007/09/13/Jaramillo_ComparativeLCACoalNG.pdf, attached as Exhibit 80. The cited estimate for the greenhouse gas emissions of liquefaction, transport, and regasification are derived by adding figures for these phases recorded in Figure 6S, p. 9 the supporting information for this article, which is available at http://pubs.acs.org/doi/suppl/10.1021/es063031o/suppl_file/es063031osi20070516_042542.pdf, and is attached as Exhibit 81 ("Jaramillo Supporting Information"). An earlier, related report with some additional information is Paulina Jaramillo, W. Michael Griffin, H. Scott Matthews, *Comparative Life Cycle Carbon Emissions of LNG Versus Coal and Gas for Electricity Generation* (2005), available at http://www.ce.cmu.edu/~gdrg/readings/2005/10/12/Jaramillo_LifeCycleCarbonEmissionsFromLNG.pdf, and attached as Exhibit 82.

[215] *See, e.g.*, Jaramillo Supporting Info, *supra* n.214, at 9.

Figure 1: Life-Cycle Emissions of LNG, Natural Gas, and Coal in Electricity Generation[216]



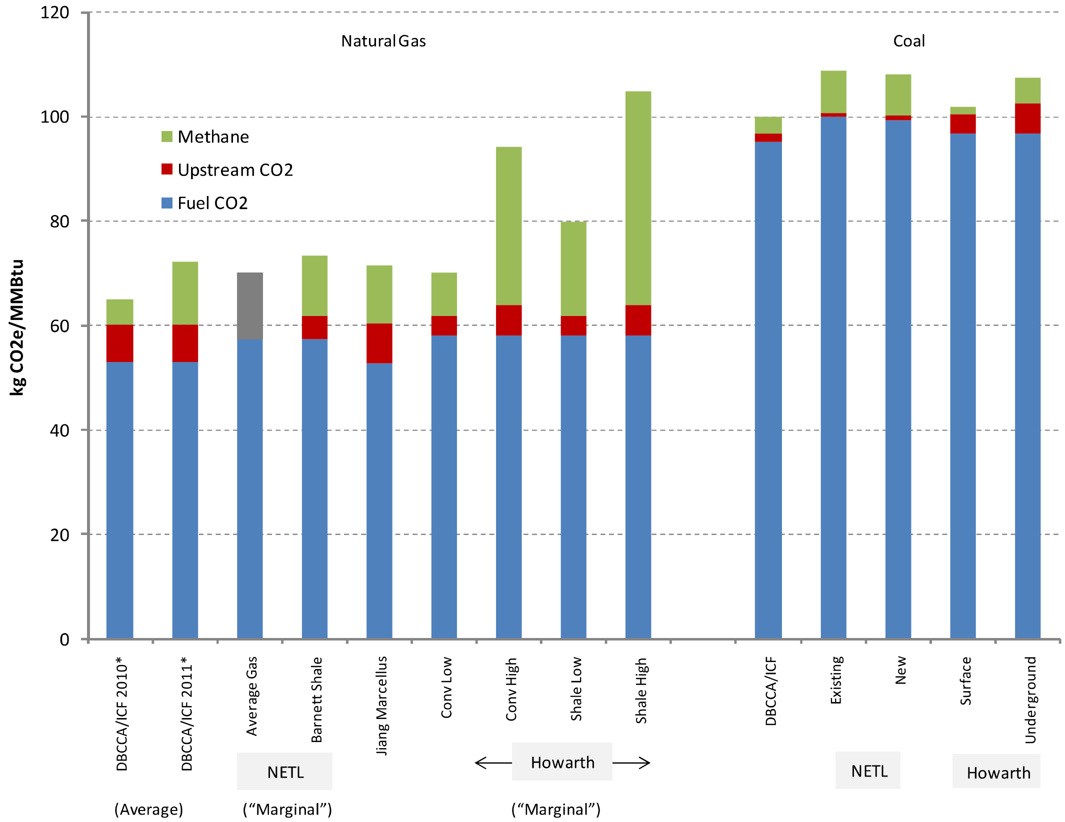
Moreover, Jaramillo's analysis understates LNG's lifecycle greenhouse gas emissions, because this analysis does not reflect recent studies that have raised estimates for emissions associated with natural gas production. The Jaramillo studies were conducted prior to the shale gas boom. Some studies have found shale gas production's methane emissions to be drastically higher than those of conventional gas production. Moreover, in April 2011 (well after the Jaramillo studies were published), EPA released improved methodologies for estimating fugitive methane emissions from all natural gas systems (unconventional and otherwise), which lead to higher estimates.[217]

These recent studies estimate that aggregate domestic natural gas production releases at least 44 pounds of CO_2e per MMBtu. A report from the Worldwatch Institute and Deutsche Bank summarizes much of the recent work.[218] Specifically, the Worldwatch Report synthesizes three other reports that used "bottom-up" methodologies to estimate natural gas production emissions, prepared by Dr. Robert Howarth et al., of Cornell,[219] Mohan Jiang et al. of Carnegie-Mellon,[220] and Timothy Skone of NETL.[221] The

[216] From Jaramillo 2007, *supra* n.214, at 6,295. "SNG," in the figure, refers to synthetic natural gas made from coal.
[217] EPA, *Inventory of U.S. Greenhouse Gas Emissions And Sinks: 1990 – 2009,* U.S. EPA, EPA 430-R-11-005, attached as Exhibit 83. The executive summary to this document is attached as Exhibit 84.
[218] Mark Fulton *et al.*, *Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal* (Aug. 25, 2011) ("Worldwatch Report"), attached as Exhibit 85.
[219] Robert W. Howarth *et al.*, *Methane and the greenhouse-gas footprint of natural gas from shale formations*, Climactic Change (Mar. 2011), attached as Exhibit 86.
[220] Mohan Jiang *et al.*, *Life cycle greenhouse gas emissions of Marcellus shale gas*, Environ. Res. Letters 6 (Aug. 2011), attached as Exhibit 87.

Worldwatch Report separately derived a "top-down" estimate, which produced a result similar to the NETL estimate.[222] These various assessments are summarized in the following chart.

Figure 2: Comparison of Recent Life-Cycle Assessments[223]



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

As this figure demonstrates, although the 2011 studies differ, most of them estimate production greenhouse gas emissions (combined methane and "upstream CO_2") in a similar range. Synthesizing these studies, the Worldwatch Report estimated normalized life-cycle GHG emissions from domestic natural gas production (i.e., excluding

[221] Timothy J. Skone, *Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction and Delivery in the United States*, Presentation to Cornell (May 12, 2011), attached as Exhibit 88.
. NETL has also published a fuller version of this analysis. *See also* Timothy J. Skone, *Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production* (Oct. 24, 2011), attached as Exhibit 89.
[222] Worldwatch Report, *supra* n.218, at 9.
[223] *Id.* at 3.

liquefaction, transport, and gasification of LNG) at approximately 20.1 kilograms, or over 44 pounds, of CO_2e/MMBtu,[224] although, as the above figure shows, some studies estimate that production emissions are significantly higher. The JISEA study generated a similar estimate of production greenhouse gas emissions: 78g CO2e/kWh, or approximately 23kg, of CO_2e/MMbtu.

Jaramillo used production emission estimates that are much lower than those produced by the more recent studies, and using the recent and higher figures appears to erode what little climate advantage Jaramillo found LNG to have over coal. Jaramillo used estimates of 15.3 to 20.1 pounds CO_2e/ MMBtu, *i.e.*, estimates that were at least 24 pounds lower than the 2011 studies'.[225] Jamarillo estimated total life-cycle emissions for LNG at 149.6 to 192.3 lbs CO_2e/MMBtu.[226] Simply increasing these life-cycle estimates by 24 lbs CO_2e represents a 12% to 16% increase in total emissions. This increase substantially erodes any climate advantage LNG-fired electricity generation may have over coal-fired generation.

Finally, any LNG exported by Southern LNG will likely have life cycle emissions that are even higher than the above estimates. The studies synthesized in the Worldwatch report generally estimate gas production emissions in aggregate, mixing conventional gas extraction with unconventional sources such as shale gas. As noted above, the EIA Export Study predicts that extraction induced by exports will overwhelmingly be from shale gas sources,[227] and at least some sources have found that shale gas has higher production emissions than conventional sources.[228] EPA recently estimated methane

[224] *Id.* at 15 Ex. 8.
[225] Jaramillo Supporting Information, *supra* n.214, at 8.
[226] *Id.*
[227] EIA Export Study, *supra* n.13, at 11.
[228] Although JISEA recently found greenhouse gas emissions from unconventional production in the Barnett shale to be "similar to levels reported in the literature from conventional natural gas," JISEA, *supra* n.212, at 4, that study's estimates may be too low. First, the JISEA study used data from the Barnett Shale, which is located in an ozone nonattainment area where emissions are likely to be rigorously controlled. It is therefore possible that its results may not generalize well to production in other plays. Second, the study did not include emissions associated with liquids unloading, a practice that involves removal of liquids from the well and consequent release of greenhouse gases, based on the assumption that liquids unloading is not frequently practiced in unconventional production. A recent industry survey suggests that liquids unloading is in fact practiced in unconventional production, however, so it may be appropriate to add emissions from liquids unloading to JISEA's life-cycle emissions total. Adding emissions associated with liquids unloading would contribute an additional 6 to 28 grams of CO2e/kWh, or even 100g under low-recovery conditions. JISEA, *supra* n.212, at 29 (citing Terri Shires & Miriam Lev-On, Characterizing Pivotal Sources of Methane

emissions from a conventional well completion at only 0.80 tons, while completion of a hydraulically fractured well yielded 158.55 tons of methane.[229] Further, the possibility that unconventional production induced by exports could release substantial quantities of greenhouse gases highlights the need for a thorough study regarding the indirect and cumulative impacts of export prior to any DOE/FE authorization. Further study is similarly needed to combine the analysis of export on fuel switching domestically with life-cycle emissions of LNG exports. In light of the evidence presented above, it is unlikely that LNG export will reduce global greenhouse gas emissions.

2. Exports' Price Increases Will Harm U.S. Workers and the US Economy

Domestic gas price increases that will result from exports will have far-reaching effects on the U.S. economy. Consumers will face higher total gas bills despite reducing their consumption of gas. This will reduce effective household income and lead to job losses in gas-dependent industries. Although exports will create some jobs in gas production, Southern LNG overstates this effect, and jobs created in gas production will be equaled if not outnumbered by jobs lost in other sectors. Considering all of these effects, exports will merely transfer wealth from wage-earners and middle-class households to shareholders in gas production companies, a regressive redistribution of wealth contrary to the public interest.

Southern LNG's job creation and economic benefit arguments fail to acknowledge these factors because they rest on a flawed "input-output" method of assessing economic consequences. Southern LNG provides a Navigant study based in the "RIMS II" input-output model of economic analysis. App. at appx. B pp. 20-21. To use this model, the user inputs a description of economic activity in a given set of economic sectors, and the model responds by tracing this spending through the economy. Specifically, the model uses accounting tables to track how the initial expenditure will flow through various industrial sectors and then uses local multipliers to estimate how this allocation will alter employment decisions. This type of modeling suffers from numerous well-documented limits that lead it to drastically overstate economic benefits. The more sophisticated modeling recently completed by NERA addresses some of these limits, and concludes that exports will harm wage-earners almost as much as it will benefit gas company shareholders. Even the NERA study, however, is based on input-output modeling (there, IMPLAN) and fails to overcome some of the limitations inherent in this technique. These limitations are discussed in depth in Amanda Weinstein and Mark D. Partridge, *The Economic Value of Shale Natural Gas in Ohio*, OHIO STATE UNIVERSITY, Swank

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Emissions from Unconventional Natural Gas Production 11-14 (2012), available at http://anga.us/media/249160/anga%20api%20survey%20report%201%20june%20final.pdf, attached as Exhibit 79).

[229] *See* O&G NSPS TSD at 4-7 (Table 4-2).

Program in Rural-Urban Policy Summary and Report (December 2010) ("Ohio Study").[230] Further limitations are discussed by David Kay, *The Economic Impacts of Marcellus Shale Gas Drilling: What Have We Learned? What are the Limitations?* (Apr. 2011).[231] Because of these limits, the Southern LNG and NERA studies fail to acknowledge many of the drawbacks of exports.

Perhaps the simplest flaw in Southern LNG's modeling is that Southern LNG appears to claim credit for jobs "supported" by its activities rather than jobs "created." That is, Southern LNG argues that every job involved in production of the gas that Southern LNG seeks to export (or the additional gas needed to run liquefaction facilities), for example, is a job that should be attributed to the Southern LNG project.[232] Sierra Club agrees that much of this gas will come from newly induced production, but, as Southern LNG's Navigant analysis acknowledges elsewhere, exporting 0.5 bcf/d of gas will not induce a full 0.5 bcf/d of production. App. at apx. A, p. 45; *see also supra* Part III.C.1.b.i. Jobs associated with production that would have occurred anyway are not "created by" the Southern LNG project, and cannot be treated as a benefit of the project.

Failing to distinguish jobs "supported" from those "created" is an aspect of a second and much larger problem with most input-output models: the failure to consider counterfactual scenarios. Southern LNG's Navigant study maps the consequences of particular expenditures, rather than asking how the economy might have grown had investors and regulators made different choices. It does not consider how the particular choice at issue might displace other economic activity. The absence of counterfactual analysis is at the core of the Ohio Study's critique of input-output analyses in the gas production context.[233] As the Ohio Study explains, studies like Navigant's "do not include various displacement effects and do not reflect the true counterfactual of comparing what would have happened *without*" the activity in question. [234] Looking at the particular case of input-output models of oil and natural gas drilling, the Ohio Study explains that these omitted factors include "higher local wages and land costs, *which reduce employment that would have occurred elsewhere in the economy*. Likewise, the environmental effects may reduce activity in the tourism sector and other residents may not want to live near such degrading activity."[235]

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[230] Attached as Exhibit 90.
[231] Attached as Exhibit 91.
[232] *Id.* at 8, 36-37. *See also* App. at 30 ("An even greater number of jobs, and far greater overall economic benefits, will result from the exploration and production of the 0.5 Bcf per day of gas required for the SLNG Export Project.").
[233] Ohio Study, *supra* n.230, at 11.
[234] *Id.* (emphasis in original).
[235] *Id.*

When counterfactuals are considered, claims of job creation falter. For example, NERA concluded that exports, by raising gas prices, would eliminate jobs in manufacturing and other industries in numbers that offset jobs created by induced gas production.[236] On this basis, NERA concludes that exports will not raise U.S. employment. But even NERA's counterfactual considers only part of the picture. Induced production resulting from export will impact other industries in ways unrelated to gas prices, such as harming tourism.[237] Gas production harms tourism by clogging roads, impacting infrastructure, diminishing the scenic value of rural areas, and through other means. These tourism threats are particularly concerning for many parts of the Marcellus region, including New York's Southern Tier, where tourism is a major source of income and employment. In the Southern Tier, according to one recent study, the tourism industry directly accounts for $66 million in direct labor income, and 4.7% of all jobs, and supports 6.7% of the region's employment.[238] It appears that NERA did not consider this type of effect in its counterfactual scenario. Adding lost tourism jobs into the counterfactual further demonstrates that exports will not provide an engine for net job creation.

A third defect of input-output studies, which afflicts both the Navigant and NERA reports, is that it they do not reflect the quality or continuity of jobs, instead providing only a series of static snapshots. The studies measure "job-years" but not jobs held year to year. As the Ohio Study explains, "impact studies do not produce continuous employment numbers. If an impact study says there are 200,000 jobs, this does not mean 200,000 workers are continuously employed on a permanent basis. . . . [W]hile the public is likely more interested in continuous ongoing employment effects, impact studies are producing total numbers of supported jobs that occur in a more piecemeal fashion."[239] This failing is particularly relevant here, because the manufacturing and other jobs exports will eliminate are typically high-quality, stable jobs,[240] whereas the gas production jobs induced production will create typically do not provide sustainable, well-paying local employment. This is in part because the industry's employment patterns are uneven: one study found that, in Pennsylvania, "*the drilling phase accounted for over 98% of the natural gas industry workforce* engaged at the drilling

[236] NERA, *supra* n.17, at 2. Unlike SLNG's Southern LNG's Navigant study, the NERA study (despite being input-output based) attempts to consider a counterfactual scenario in which exports do not occur and other industries benefit from lower gas prices.
[237] *See, e.g.*, CJ Randall, Hammer Down: A Guide to Protecting Local Roads Impacted by Shale Gas Drilling (Dec. 2010), attached as Exhibit 92; Susan Riha & Brian G. Rahm, *Framework for Assessing Water Resource Impacts from Shale Gas Drilling* (Dec. 2010), Attached as Exhibit 93; Cornell study, *supra* n.256, at 8.
[238] Andrew Rumbach, Natural Gas Drilling in the Marcellus Shale: Potential Impacts on the Tourism Economy of the Southern Tier (2011), attached as Exhibit 94.
[239] Ohio Study, *supra* n.230, at 11.
[240] NERA report, *supra* n.17, at 62.

site," and that complementary Wyoming data showed a similar drop-off.[241] As a result, drilling jobs correspond to the boom and bust cycle inherent to resource extraction industries.[242] The remaining, small, percentage of production-phase and office jobs are far more predictable, but must be filled with reasonably experienced workers.[243] Although job training at the local level can help residents compete, the initial employment burst is usually made up for people from out of the region moving in and out of job sites; indeed, "[t]he gas industry consistently battles one of the highest employee turnover problems of any industrial sector."[244] As such, even if, as NERA suggests, exports will not drastically change the number of people with jobs in any given year, exports will nonetheless lead to a decline in the overall quality and stability of American jobs.

A fourth flaw in Southern LNG's Navigant study is that its input-output model may not reflect actual spending patterns, as the Ohio study explains.[245] For example, landowners given gas production leases may choose to save their money, rather than to spend it.[246] To the extent this occurs, it reduces the stimulus effect attributed to gas production.

Fifth, exports will cause distributional inequity that is ignored by Southern LNG's analysis, including Southern LNG's statements about the total amount of economic benefit that will be generated by exports. While NERA's report acknowledges this problem, it gives short shrift to it. As noted above, exports will cause many wage-earners to lose their jobs or suffer decreased wage income as a result of increases in gas prices. Even employees whose jobs are not directly affected will suffer decreased "real wage growth" as gas prices and household gas expenditures increase relative to nominal wages.[247] All consumers of natural gas—residential, commercial, industrial, and electricity generating users—will suffer higher gas bills despite reducing their gas consumption.[248] NERA concludes that losses to "[h]ouseholds with income solely from wages or transfers" will be slightly smaller than gains experienced by owners of gas resources and shareholders in gas companies.[249] Although NERA purports to predict

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[241] *See* Jeffrey Jacquet, *Workforce Development Challenges in the Natural Gas Industry*, at 4 (Feb. 2011) (emphasis in original), attached as Exhibit 95.
[242] *Id.*
[243] *Id.* at 4-5, 12-14.
[244] *Id.* at 13.
[245] Ohio Study, *supra* n.230, at 14-15.
[246] *Id.*
[247] NERA report, *supra* n.17, at 9.
[248] EIA Export study, *supra* n.13, at 11, 15. These increases are very large in absolute terms. At a minimum, in the EIA's low/slow scenario, gas and electricity bills increase by $9 billion per year, and this increase grows to $20 billion per year in other scenarios. *Id.* at 14.
[249] NERA report, *supra* n.17, at 9, 2.

changes in aggregate "welfare," its analysis appears to ignore the fact that ownership of gas company shares is not distributed evenly and to assume, without support, that none of these shares are foreign owned.[250] But the public interest analysis must account for these effects. An extensive body of economic and philosophical literature demonstrates that the marginal utility of money declines with income—an extra $100 matters less the more money a person has.[251] Indeed, the Obama Administration has repeatedly emphasized the need to avoid regressive policies that transfer wealth from the middle classes to the wealthy.[252] Last week, the President explained that "Our economic success has never come from the top down; it comes from the middle out. It comes from the bottom up."[253] Similarly, the President has warned against short-sighted management of wealth. As he explained in the 2009 State of the Union address, the nation erred when "too often short-term gains were prized over long-term prosperity, where we failed to look beyond the next payment, the next quarter, or the next election."[254] DOE/FE must not allow a "surplus [to] bec[o]me an excuse to transfer wealth to the wealthy instead of an opportunity to invest in our future."[255]

Sixth and finally, both Southern LNG's application and the NERA study fail to account for the disruption of communities that will be caused by exports and induced gas production. For example, the boom-bust cycle inherent in gas extraction can leave some regions worse off if they are unable to convert the temporary boom into permanent growth, according to research done by Cornell University's Department of City and Regional Planning on the economic impacts of the gas boom on Pennsylvania and New York. As the researchers put it:

> The extraction of non-renewable natural resources such as natural gas is characterized by a "boom-bust" cycle in which a rapid increase in economic activity is followed by a rapid decrease. The rapid increase occurs when drilling crews and other gas-related businesses move into a region

[250] *Id.* at 55 n.22.
[251] *See, e.g.*, Matthew D. Adler, *Risk Equity: A New Proposal*, 32 Harv. Envtl. L. Rev. 1 (2008).
[252] *See, e.g.,* State of the Union Address (January 24, 2012), attached as Exhibit 96, available at http://www.whitehouse.gov/the-press-office/2012/01/24/remarks-president-state-union-address
[253] Remarks by the President at the Daimler Detroit Diesel Plant, Redford, MI (Dec. 10, 2012), attached as Exhibit 97 and available at http://www.whitehouse.gov/the-press-office/2012/12/10/remarks-president-daimler-detroit-diesel-plant-redford-mi
[254] State of the Union Address (Feb. 24, 2009), attached as Exhibit 98, available at http://www.whitehouse.gov/the_press_office/Remarks-of-President-Barack-Obama-Address-to-Joint-Session-of-Congress
[255] *Id.*

> to extract the resource. During this period, the local population grows and jobs in construction, retail and services increase, though because the natural gas extraction industry is capital rather than labor intensive, drilling activity itself will produce relatively few jobs for locals. Costs to communities also rise significantly, for everything from road maintenance and public safety to schools. When drilling ceases because the commercially recoverable resource is depleted, there is an economic "bust" – population and jobs depart the region, and fewer people are left to support the boomtown infrastructure.[256]

This boom and bust cycle is exacerbated by the purportedly vast resources of the recently discovered shale gas play, because regional impacts will persist long after local benefits have dissipated, and may be destructive if communities are not able to plan for, and capture, the benefits of industrialization:

> [T]he experience of many economies based on extractive industries warns us that short-term gains frequently fail to translate into lasting, community-wide economic development. *Most alarmingly, a growing body of credible research evidence in recent decades shows that resource dependent communities can and often do end up worse than they would have been without exploiting their extractive reserve.* When the economic waters recede, the flotsam left behind can look more like the aftermath of a flood than of a rising tide.[257]

These broader, more complex effects on communities are not captured by input-output models such as those used by Southern LNG and NERA. Input output models struggle, particularly, to map these distributional effects, where some prosper while others suffer, and, more generally, are not designed to chart the long-term effects of such major dislocations. [258]

In summary, the NGA's "public interest" test requires DOE/FE to determine whether the country would be better off with Southern LNG's proposal than without it. Input-output

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[256] Susan Cristopherson, CaRDI Reports, The Economic Consequences of Marcellus Shale Gas Extraction: Key Issues 4 (2011) ("Cornell Study") (Sept. 2011) at 4. Attached"), attached as Exhibit 99.

[257] *Id.* at 6 (emphasis added).

[258] David Kay, *The Economic Impacts of Marcellus Shale Gas Drilling: What Have We Learned? What are the Limitations?* 5-6, 22-30 (Apr. 2011), attached as Exhibit 91.

-based analyses cannot answer this question, but these are the only analyses Southern LNG offers. Southern LNG's application provides no basis for concluding that the country would be better off with exports than without them. Although NERA attempted to consider counterfactual scenarios in which exports did not occur and concluded that, compared to these baselines, exports would produce a slight net economic benefit, NERA failed to consider all of the costs that exports will impose on the country, and merely looking at aggregate costs ignores distributional effects that must be considered in analysis of the public interest.

3. DOE/FE Cannot Rationally Approve Southern LNG's Export Plan On the Record Before It

The NGA, and subsequent DOE delegation orders and regulations, charge DOE/FE with determining whether or not a gas export application is in the public interest. *See, e.g.* 15 U.S.C. § 717b(a). DOE/FE must make this decision on the record before it. This means that, regardless of DOE/FE's decision to presume, initially, that an application should be granted, this presumption does not, and cannot, absolve DOE/FE of its duty to make its *own* determination. *Panhandle Producers and Royalty Owners Ass'n*, 822 F.2d at 1110-11. Simply put, "the *agency* must examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made." *Motor Vehicle Mfrs. Ass'n of the United States v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (emphasis supplied). DOE/FE cannot rationally find for Southern LNG on the record in this case.

As we have demonstrated, record support for Southern LNG's claimed benefits is extraordinarily thin. Southern LNG has submitted economic benefit information derived from input-output modeling, but the underlying model does not show whether the economy would improve *more* without Southern LNG proposal than it would without it.

Sierra Club, on the other hand, has shown that the gas and electricity price increases associated with exports will add billions of dollars in costs to consumers. These costs will propagate through the economy, retarding growth. We have also shown that the economic benefits, if any, associated with gas production increases may actually do long-term damage to the U.S. economy by plunging large regions of the country into a boom-and-bust extractive cycle. Further, we have shown that gas extraction and export have major environmental (and, hence, additional economic) costs, which Southern LNG has failed to even acknowledge.

On this record, DOE/FE cannot approve export. Were it do so, it would be violating basic norms of agency record rulemaking, as well as its own rules. *See, e.g.*, 5 U.S.C. § 706; 10 C.F.R. § 590.404 (requiring DOE/FE to base its final opinion "solely on the official record of the proceeding" and to impose terms "as may be required by the public interest" after record review).

D. If DOE/FE Does Move Forward, It Must Impose Rigorous Monitoring Conditions

If DOE/FE nonetheless approves Southern LNG's application, it must recognize its continuing duty to protect the public interest, as it explained in its *Sabine Pass* decision. This duty is of crucial importance in the context of LNG export, where circumstances are rapidly changing. DOE/FE therefore announced its intention to monitor environmental, economic, and other relevant considerations. *Sabine Pass* at 31-33. Such a monitoring provision must be imposed here, as well, but must be significantly expanded.

Specifically, although *Sabine Pass* announces an intention to monitor many different considerations, it most clearly states that the agency will act if there is a "reduction in the supply of natural gas needed to meet essential domestic needs." *Id.* at 32. This consideration is undoubtedly of great importance, but it is not the only way in which changing circumstances could imperil the public interest.

On the contrary, as we have demonstrated at length in these comments, there is strong evidence that the public interest will be impaired by gas exports. These impairments include (1) regional and national economic dislocations and disruptions caused by natural gas extraction, including by the industry's boom-and-bust cycle, (2) national increases in gas and electricity prices and resulting shifts to more polluting fuels, (3) and environmental impacts of many sorts. Any one of these categories of interests could be impaired by gas export. DOE/FE must therefore state that it will monitor each of these areas, providing specific monitoring terms and thresholds which will trigger agency actions of various types, ranging from further study through reductions in export volume or changes in timing to a revocation of DOE/FE's approval.[259]

If DOE/FE fails to include such provisions in any final approval, it will fail to fulfill its "continuing duty to protect the public interest," *id.* at 31, and so violate the Natural Gas Act. Because neither Southern LNG nor DOE/FE have described or proposed such terms, Sierra Club protests this application to the extent that DOE/FE fails to develop adequate monitoring terms of the sort we have described.

[259] Providing a clear monitoring plan of this sort will also benefit Southern LNG, which will be better able to determine when and how DOE/FE may act, improving the company's ability to plan its actions and investments.

IV. Conclusion

Sierra Club therefore moves to intervene, offers the above comments, and protests Southern LNG's export proposal for the reasons described above. Southern LNG's application is not consistent with the public interest and must be denied.

Respectfully submitted,

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

IN THE MATTER OF	)	
	)	**FE DOCKET NO. 12-100-LNG**
Southern LNG Company, L.L.C.	)	
	)	
	)	

CERTIFIED STATEMENT OF AUTHORIZED REPRESENTATIVE

Pursuant to C.F.R. § 590.103(b), I, Ellen Medlin, hereby certify that I am a duly authorized representative of the Sierra Club, and that I am authorized to sign and file with the Department of Energy, Office of Fossil Energy, on behalf of the Sierra Club, the foregoing documents and in the above captioned proceeding.

Dated at San Francisco, CA, this 17th day of December, 2012.

Ellen Medlin

____

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

IN THE MATTER OF	)	
	)	**FE DOCKET NO. 12-100-LNG**
Southern LNG Company, L.L.C.	)	
	)	
	)	

CERTIFICATE OF SERVICE

I hereby certify that I caused the above documents to be served on the applicant and all others parties in this docket, in accordance with 10 C.F.R. § 590.017, on December 17, 2012.

Dated at San Francisco, CA, this 17th day of December, 2012.

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY

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Southern LNG Company, L.L.C.	)	
	)	
	)	

VERIFICATION

WASHINGTON §
§
DISTRICT OF COLUMBIA §

Pursuant to C.F.R. §590.103(b), Ellen Medlin, being duly sworn, affirms that she is authorized to execute this verification, that she has read the foregoing document, and that facts stated herein are true and correct to the best of her knowledge, information, and belief.

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Subscribed and sworn to before me this 17 day of December, 2012.

Notary Public

MARK DAVID BOSLER
Commission # 1977496
Notary Public - California
San Francisco County
My Comm. Expires Jun 3, 2016

My commission expires: 6/3/16

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/

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(200*9)), 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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Contents

Contents

Figures

Contents

Tables

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 andthe 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.

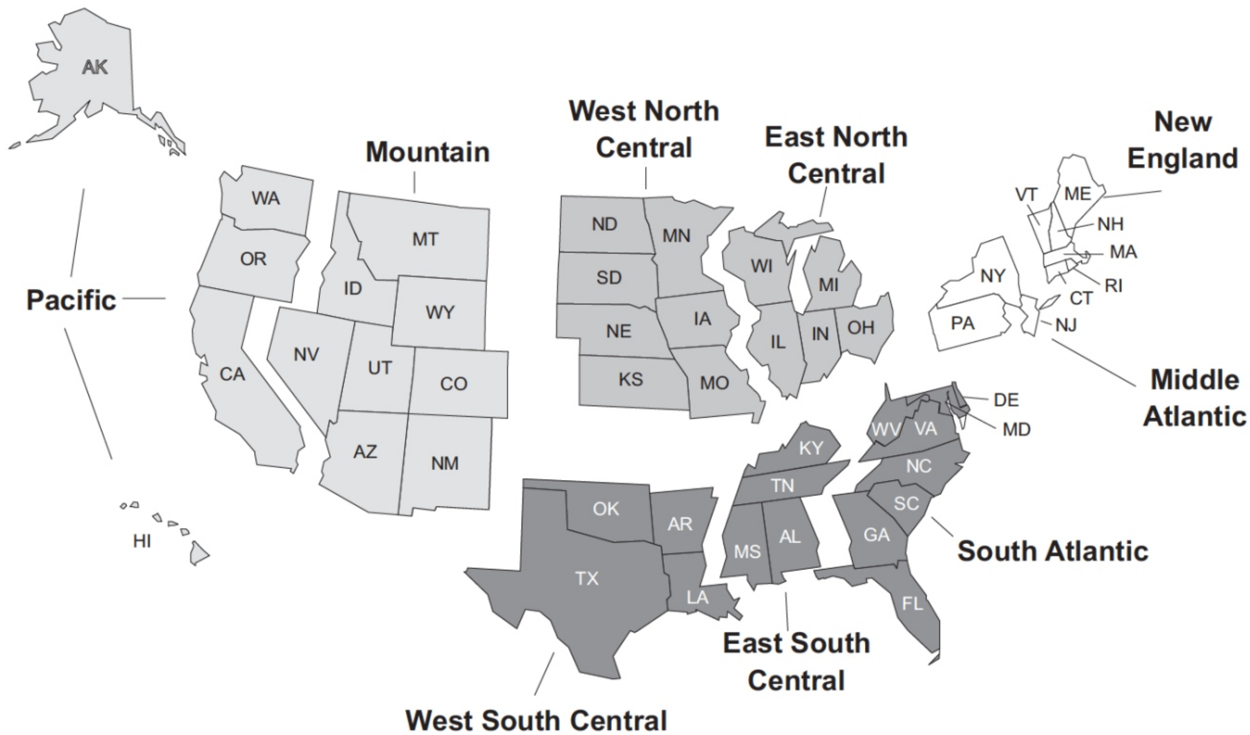
Because energy markets are heterogeneous, a single methodology does not adequately represent all supply, conversion, and end-use demand sectors. The modularity of the NEMS design provides the flexibility for each component of the U.S. energy system to use the methodology and coverage that is most appropriate. 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

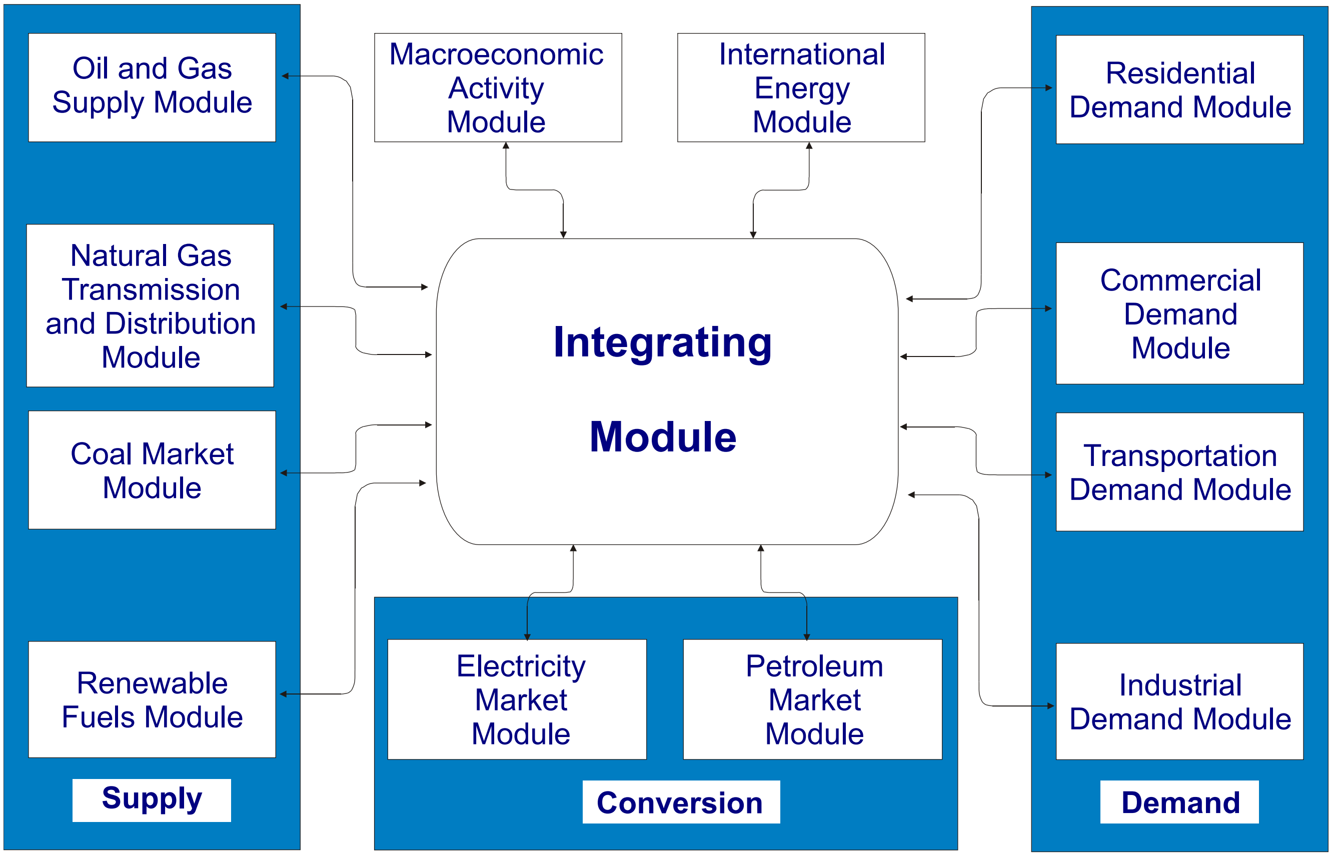
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

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.

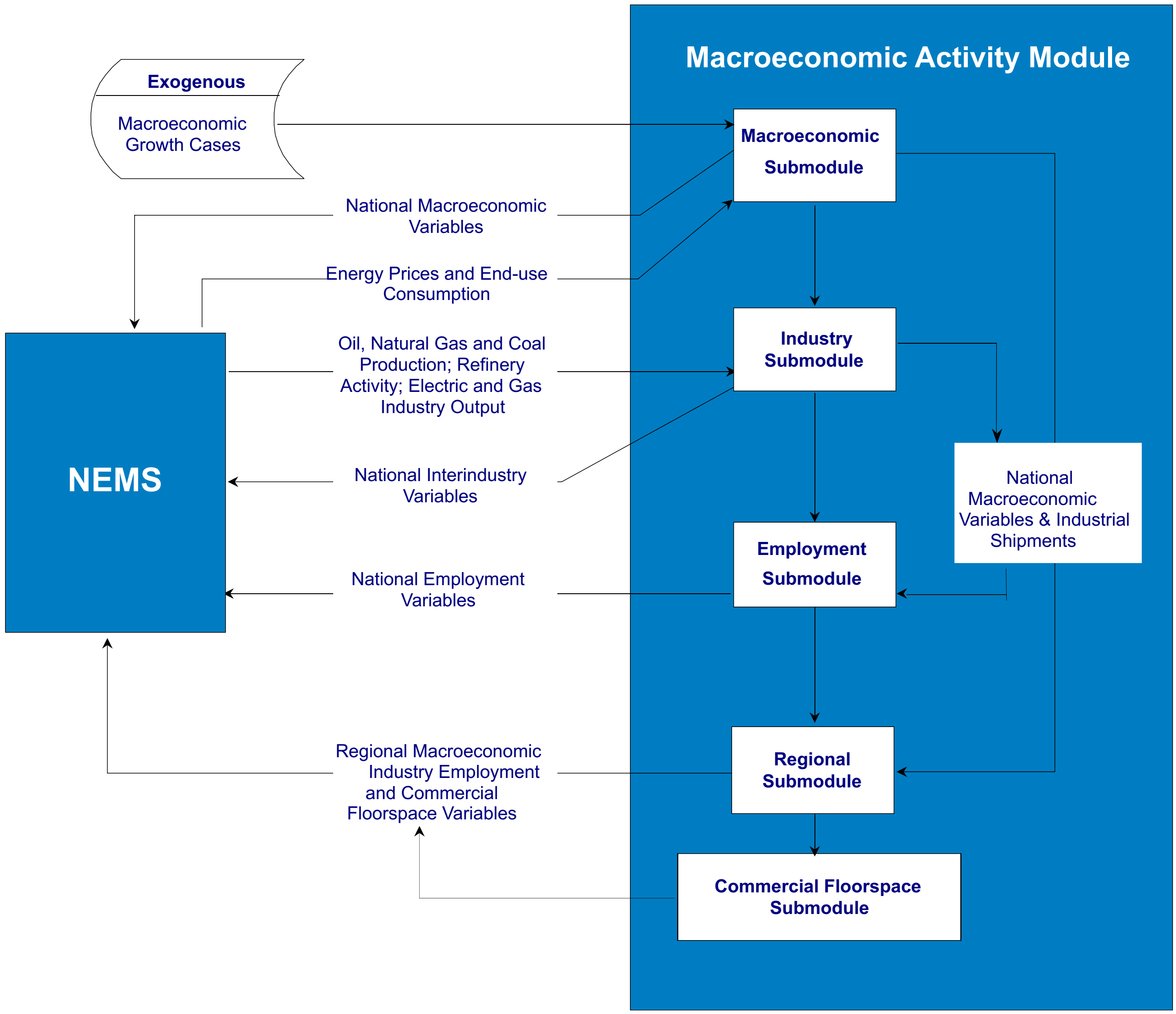
The Industry Submodule takes the final demand projections from the Macroeconomic Submodule as inputs to provide projections of output and other key indicators for 61 sectors, covering the entire economy. This is later aggregated to 41 sectors to provide information to NEMS. The Industry Submodule insures 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.

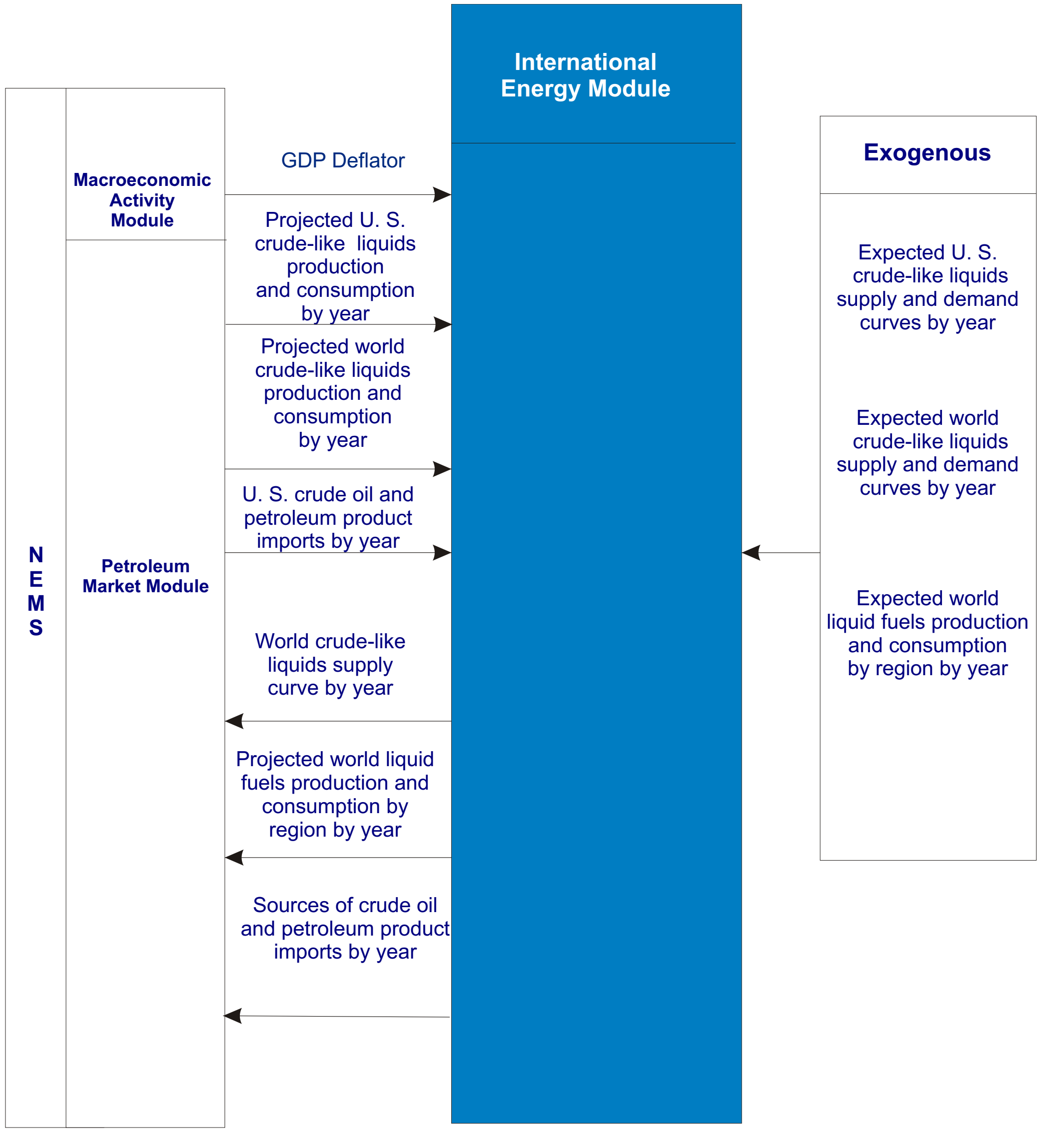
Because U.S. production and consumption of conventional liquids are dynamic values (output from NEMS), all other world regions have been proportionally updated such that the world liquids production and consumption reflect the corresponding value as in the *International Energy Outlook* (*IEO*).

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

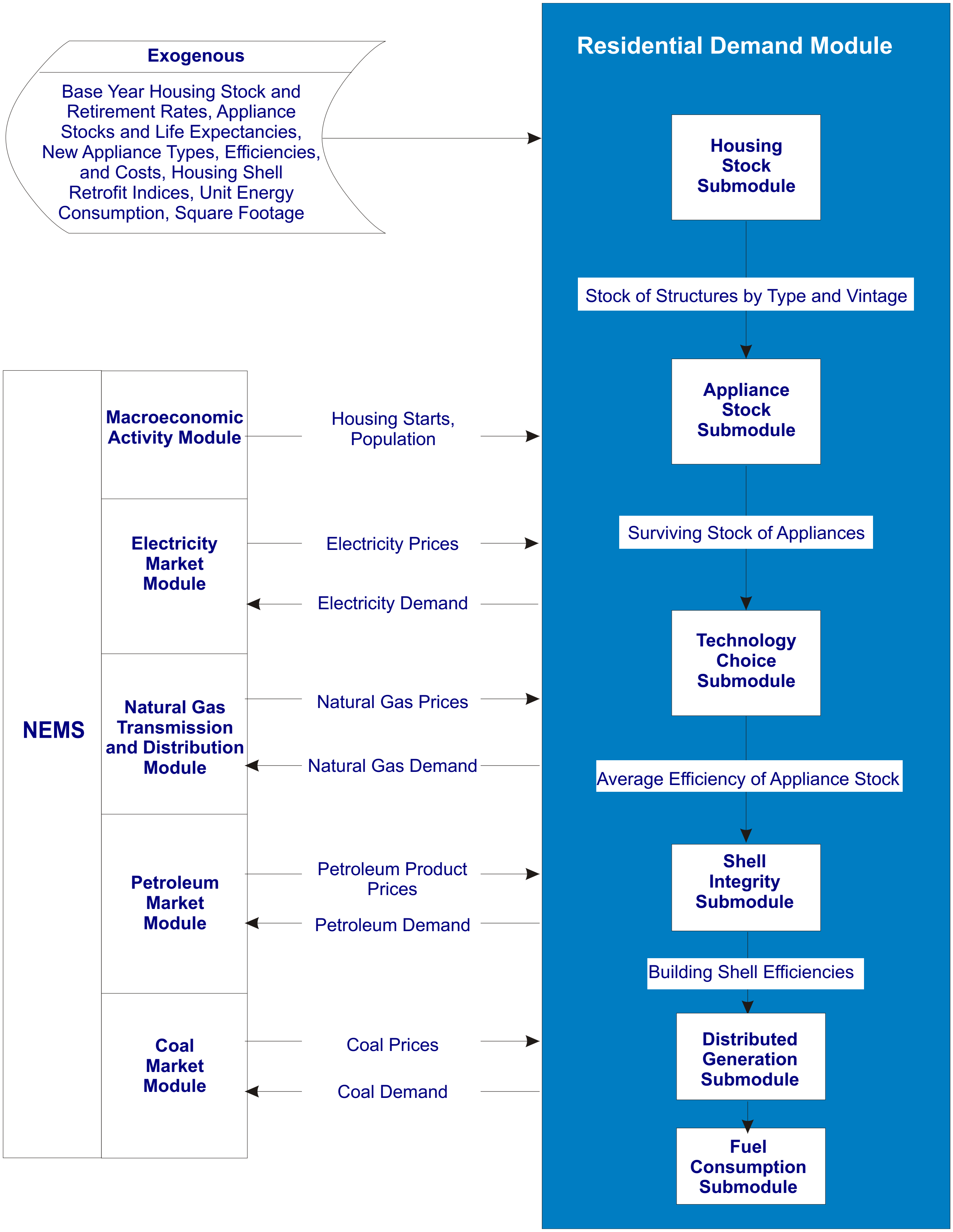


Table 2. NEMS Residential Module Equipment Summary

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

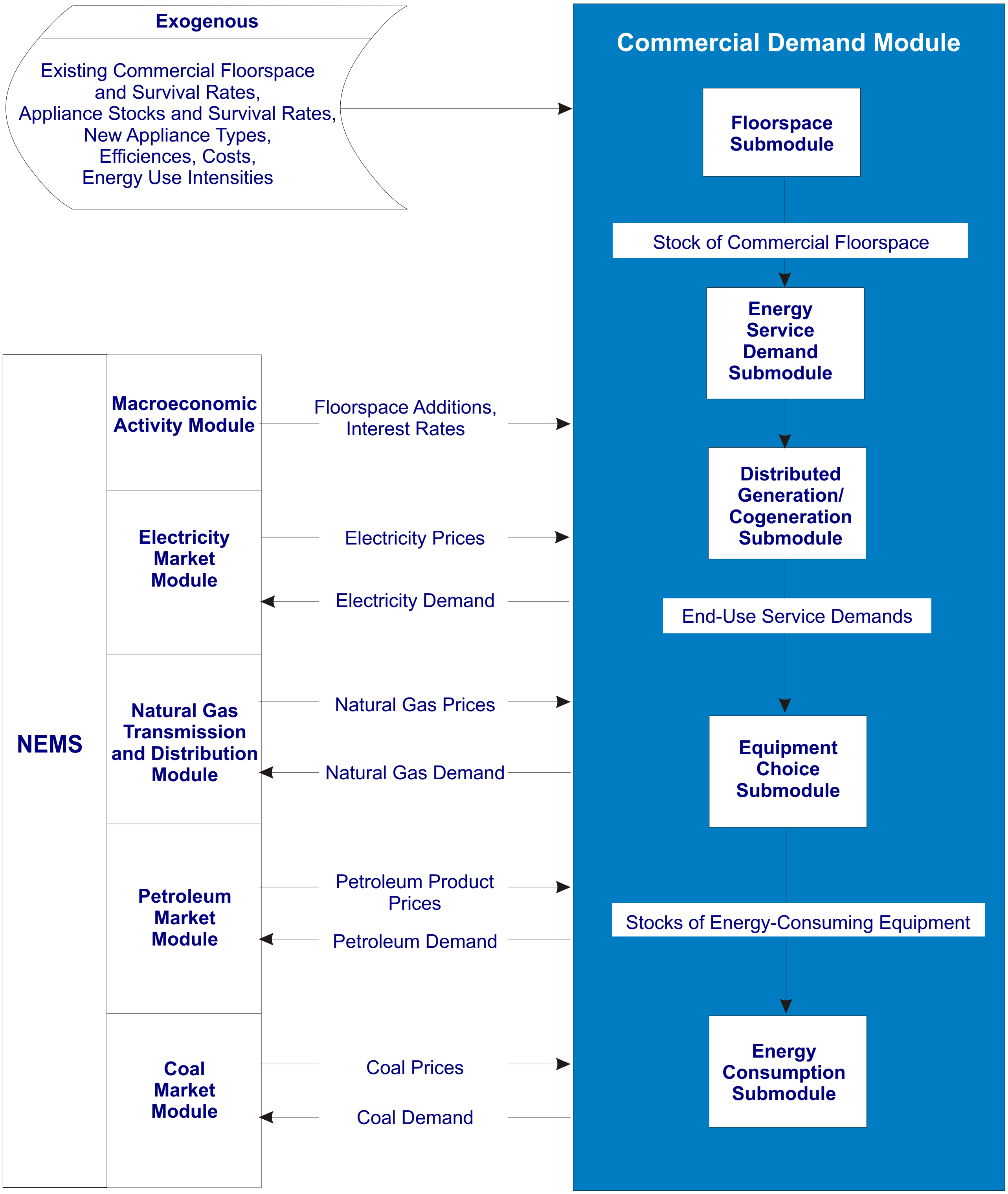
The base stock of commercial floorspace by Census division and building type is derived from EIA's 2003 Commercial Buildings Energy Consumption Survey (CBECS). CDM receives projections of total floorspace by building type and Census division from the macroeconomic activity module (MAM) based on IHS Global 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

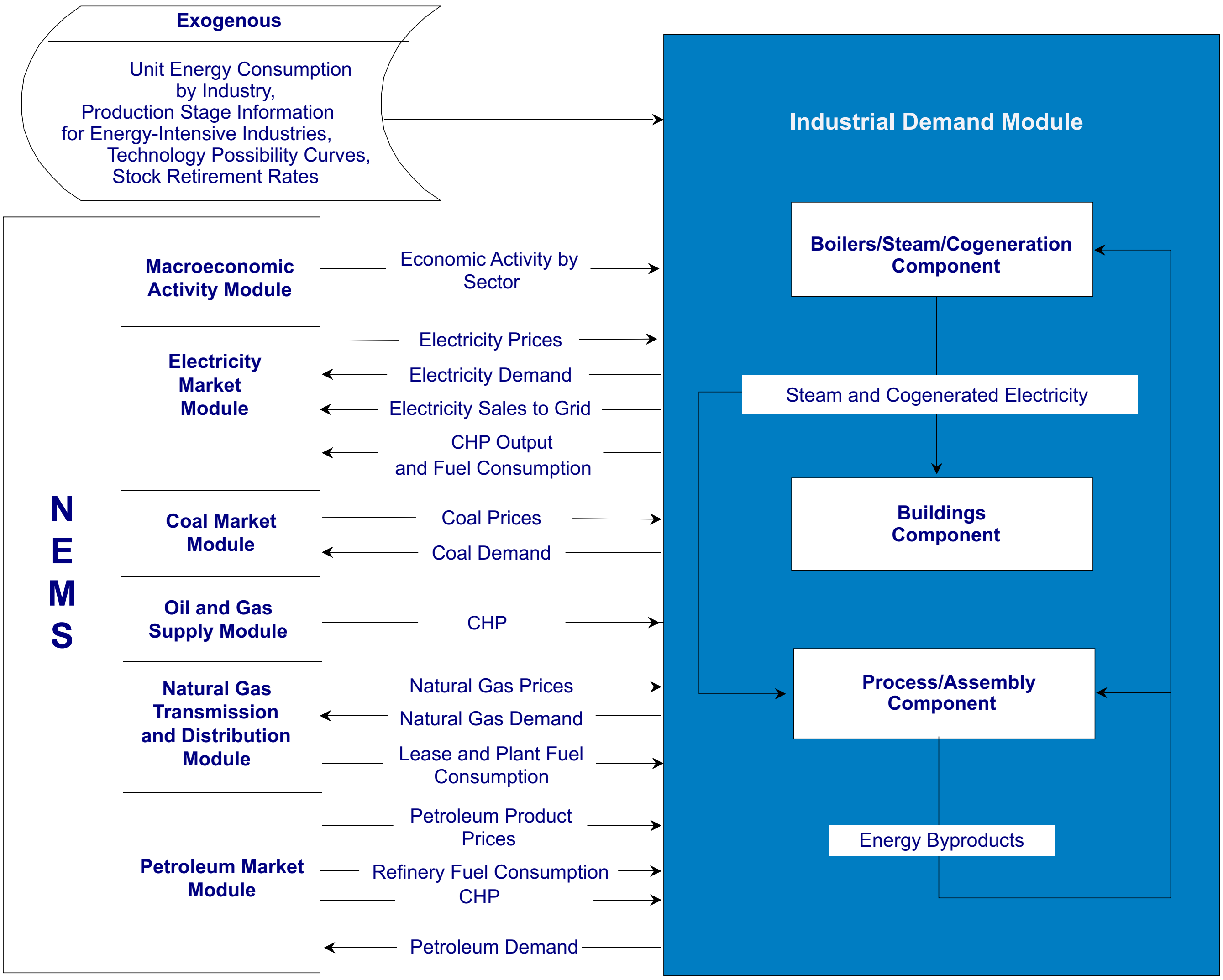
Energy-Intensive Manufacturing	**Nonmanufacturing Industries**
Food and Kindred Products (NAICS 311)	Agricultural Production - Crops (NAICS 111)
Paper and Allied Products (NAICS 322)	Other Agriculture including Livestock (NAICS 112-115)
Bulk Chemicals (NAICS 325)	Coal Mining (NAICS 2121)
Glass and Glass 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 Sales, stocks, and characteristics of vehicle types by size class Vehicle-miles traveled Fuel economy by technology type Alternative-fuel vehicle sales by technology type Light-duty commercial fleet vehicle characteristics	Energy product prices Gross domestic product Disposable personal income Industrial output Vehicle sales International trade Natural gas pipeline Population	Existing vehicle stocks by vintage and fuel economy Vehicle survival rates New vehicle technology characteristics Fuel availability Commercial availability Vehicle safety and emissions reglations Vehicle miles-per-gallon degradation rates

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

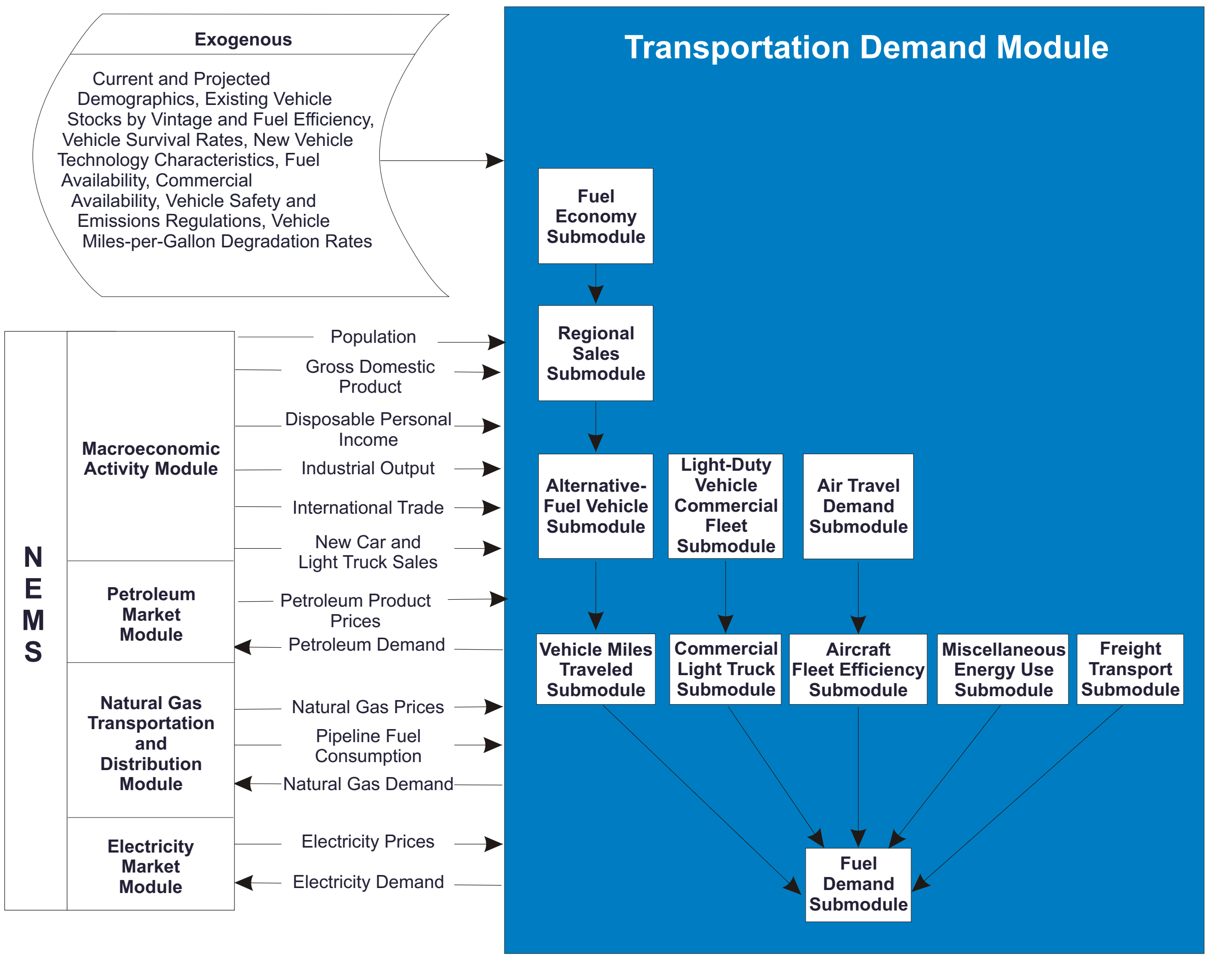
Table 9. Examples of Midsize Automobile Attributes

	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, as follows:

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

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.

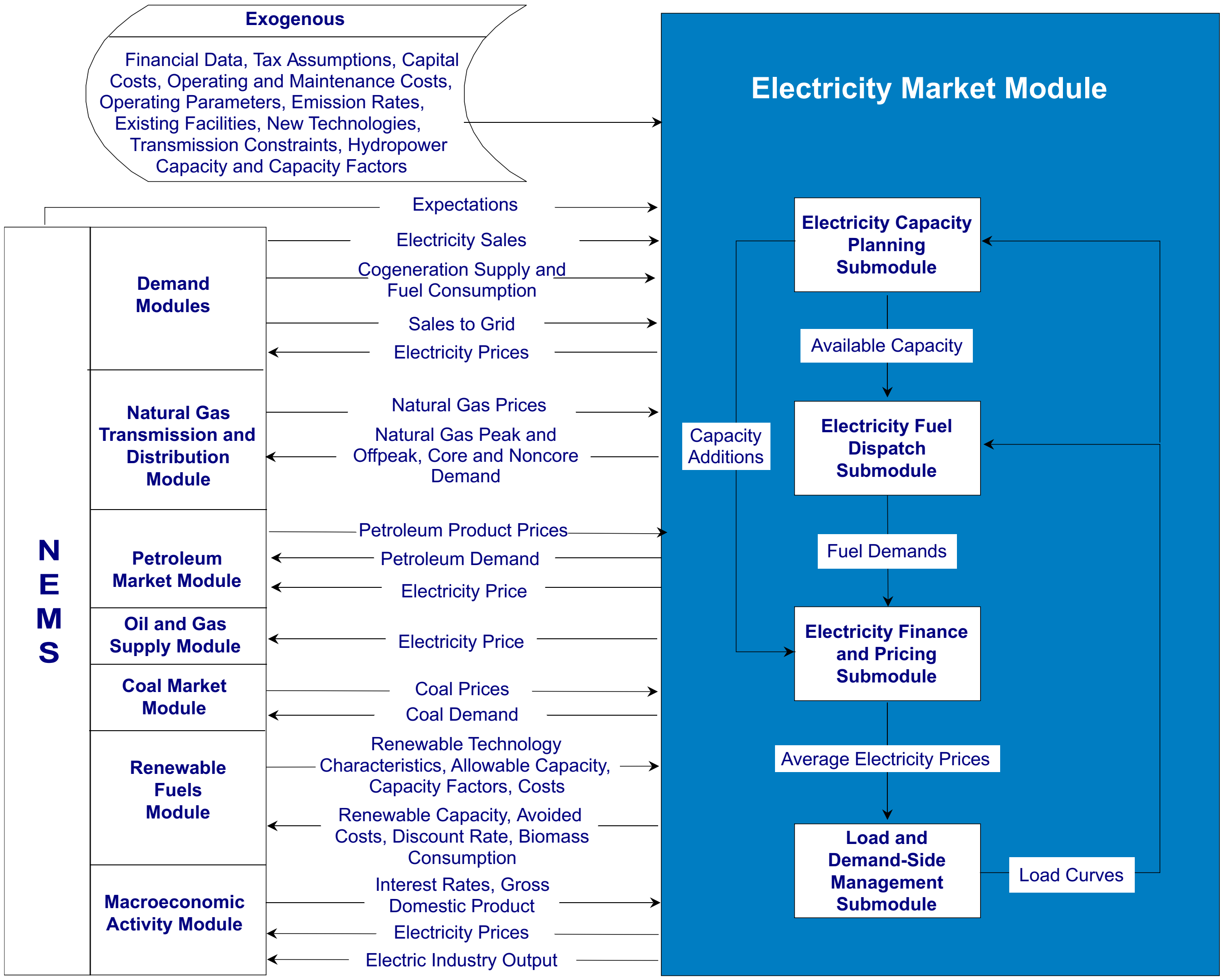
Electricity Capacity Planning Submodule

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 Fuel demands Capacity additions Capital requirements Emissions Renewable capacity Avoided costs	Electricity sales Fuel prices Cogeneration supply and fuel consumption Electricity sales to the grid Renewable technology characteristics, allowable capacity, and costs Renewable capacity factors Gross domestic product Interest rates	Financial data Tax assumptions Capital costs Operation and maintenance costs Operating parameters Emmissions rates New technologies Existing facilities Transmission constraints

Figure 9. Electricity Market Module Strucuture



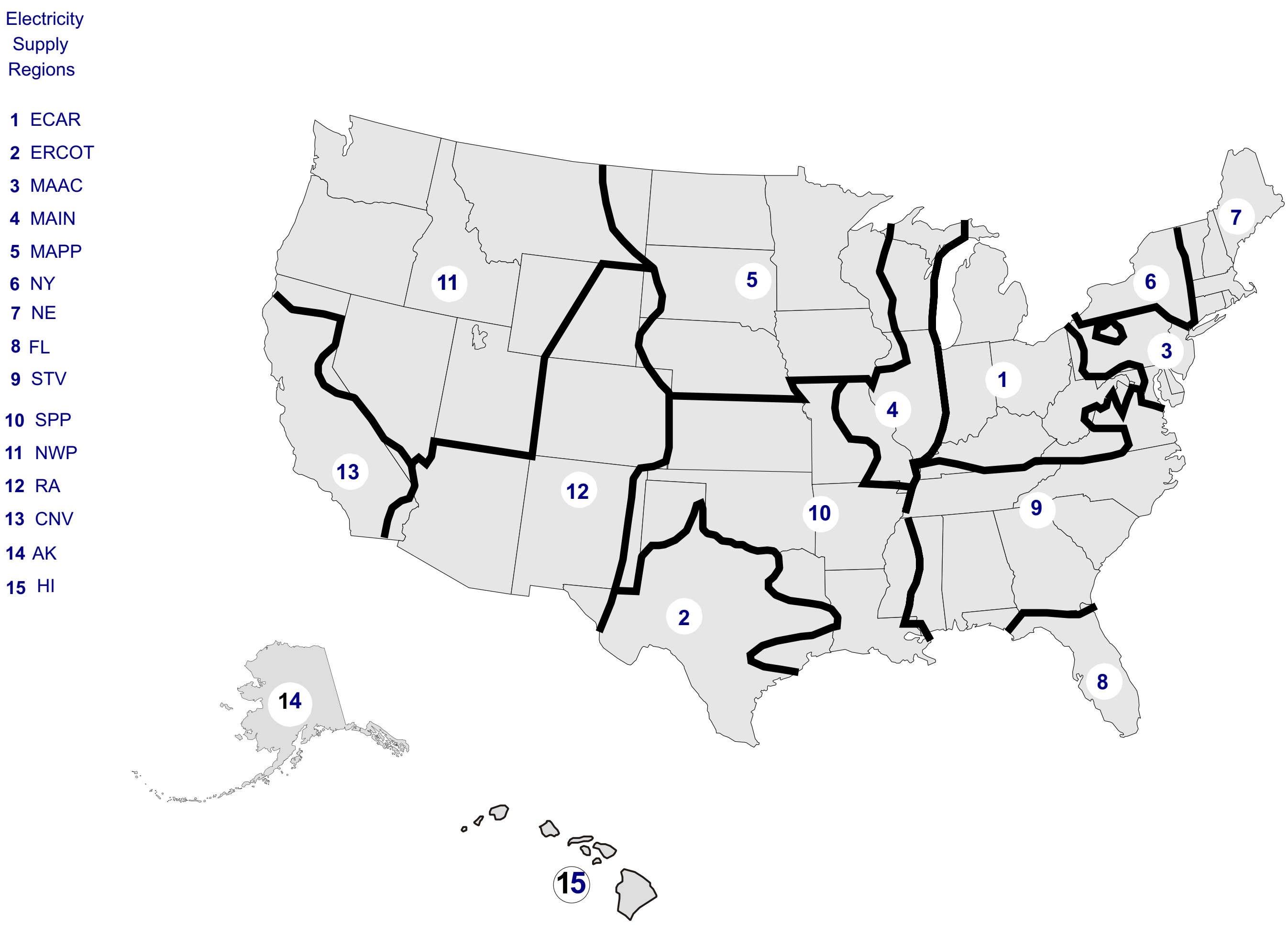
by plants that are cheaper to build than baseload plants and cheaper to operate than peak load plants.

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 combustion 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

1Overnight 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.

2Online 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.

3Because 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.

4For 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

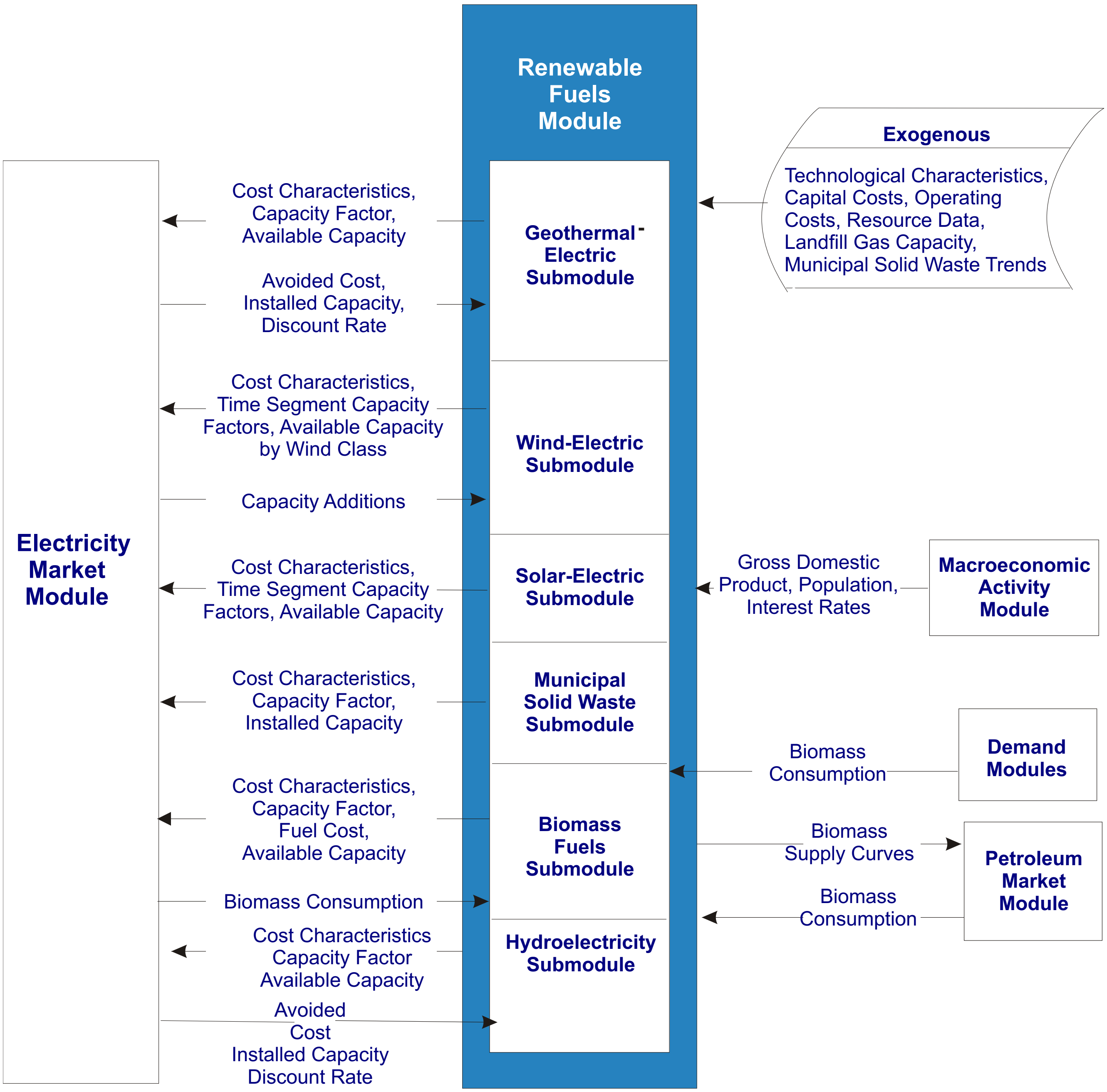
The wind-electric submodule projects the availability of wind resources as well as the cost and performance of wind turbine generators. This information is passed to EMM so that wind turbines can be built and dispatched in competition with other electricity generating technologies. The wind turbine data 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 Capital costs Operating costs (including wood supply prices for the wood submodule) Capacity factors Available capacity Biomass fuel costs Biomass supply curves	Installed energy production capacity Gross domestic product Population Interest Rates Avoided cost of electricity Discount rate Capacity additions Biomass consumption	Site-specific geothermal resource quantity data Site-specific wind resource quality data Plant utilization (capacity factor) Technology cost and performance parameters Landfill gas capacity

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 nonassociated and Canadian conventional natural gas suply curves Cogeneration from oil and gas producton Reserves and reserve additions Drilling levels Domestic associated-dissolved gas production	Domestic and Canadian natural gas production and wellhead prices Crude oil demand World oil price Electricity price Gross domestic product Inflation rate	Resource levels Initial finding rate parameters and costs Production profiles Tax parameters

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.

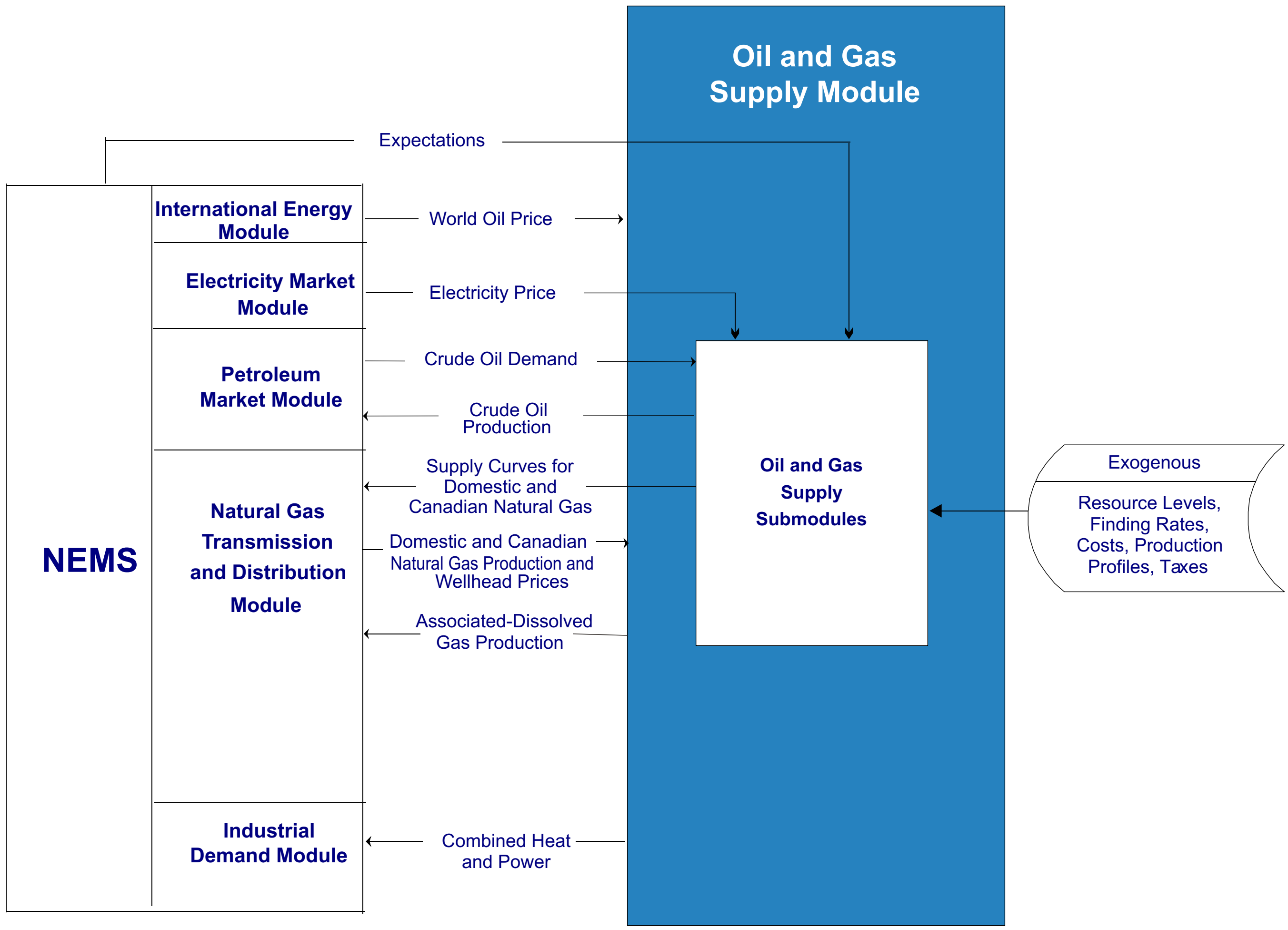
Unconventional Gas Recovery Supply Submodule

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.

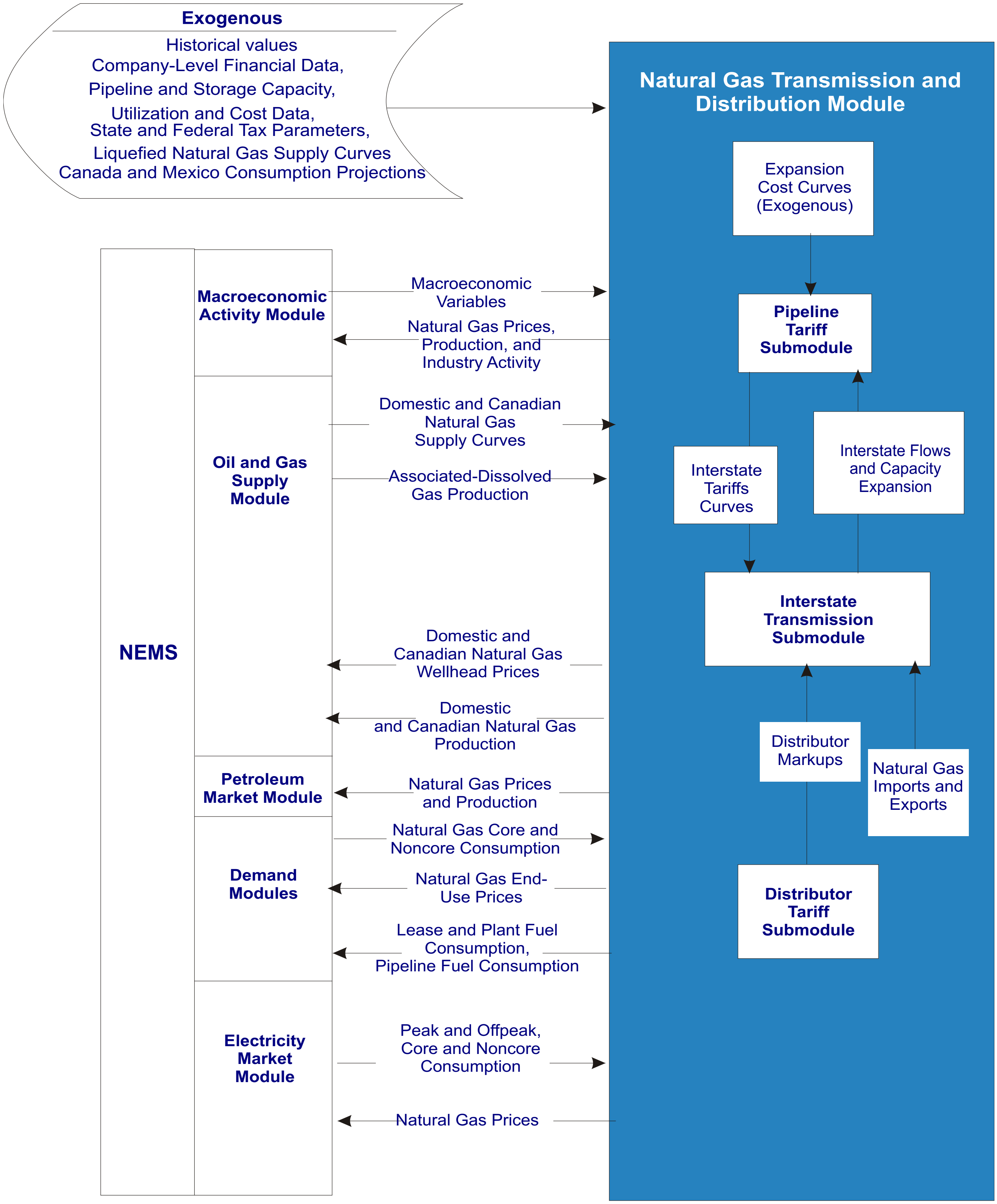
Arcs between transshipment nodes, from the transshipment nodes to end–use sectors, and from supply sources to transshipment nodes are assigned tariffs. The tariffs along interregional arcs reflect reservation (represented with volume dependent curves) and usage fees and are established in the pipeline 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

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).

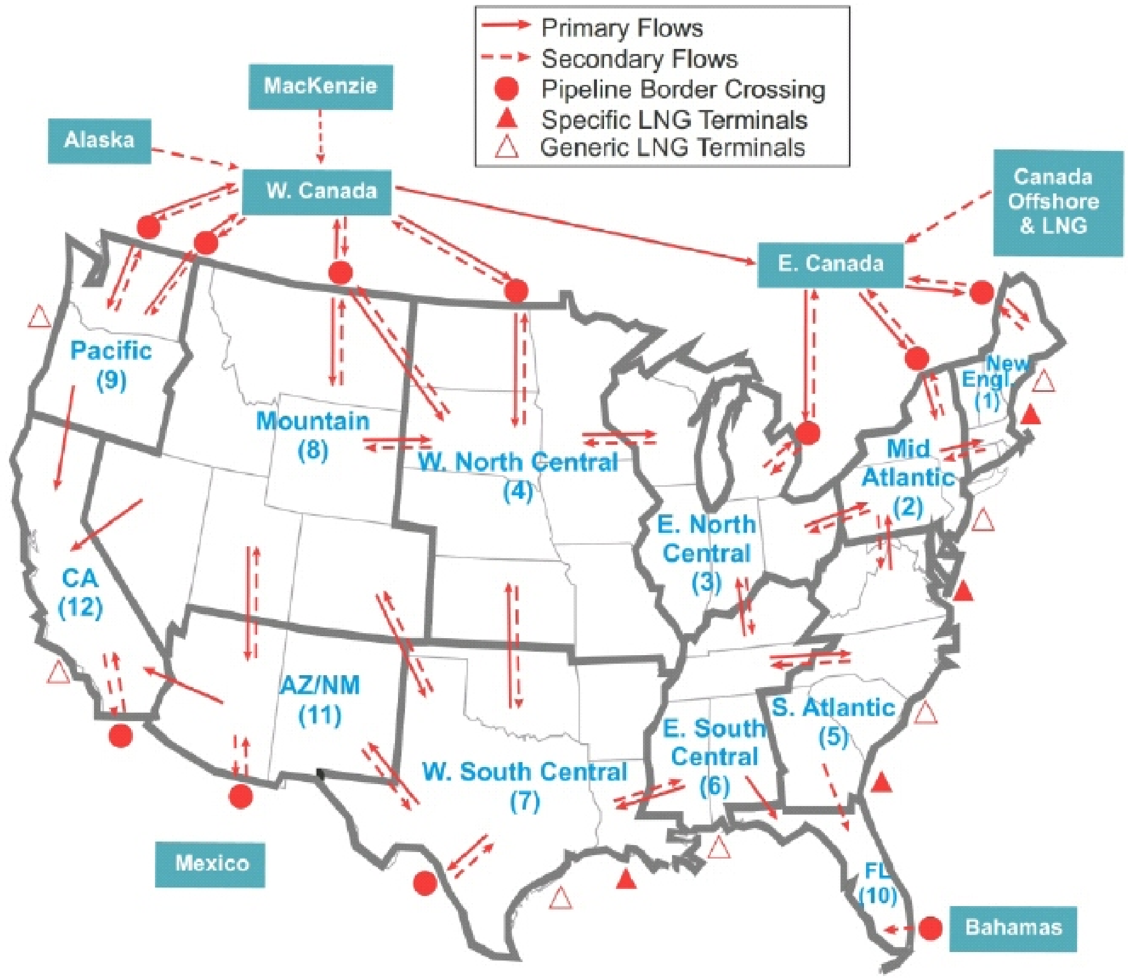
Distributor tariffs for all but the transportation sector are set using econometrically estimated equations. The natural gas vehicle sector markups are calculated separately for fleet and personal vehicles and account for distribution to delivery stations, retail markups, and federal and state motor 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 Crude oil imports and exports Crude oil demand Petroleum product imports and exports Refinery activity and fuel use Ethanol demand and price Combined heat and power (CHP) Natural gas plant liquids production Processing gain Capacity additions Capital expenditures Revenues	Petroleum product demand by sector Domestic crude oil production World oil price International crude oil supply curves International product supply curves International oxygenates supply curves Natural gas prices Electricity prices Natural glas production Macroeconomic variables Biomass supply curves Coal prices	Processing unit operating parameters Processing unit capacities Product specifications Operating costs Capital costs Transmission and distribution costs Federal and State taxes Agricultural feedstock quantities and costs CHP unit operating parameters CHP unit capacities

Figure 16. Petroleum Market Module Structure

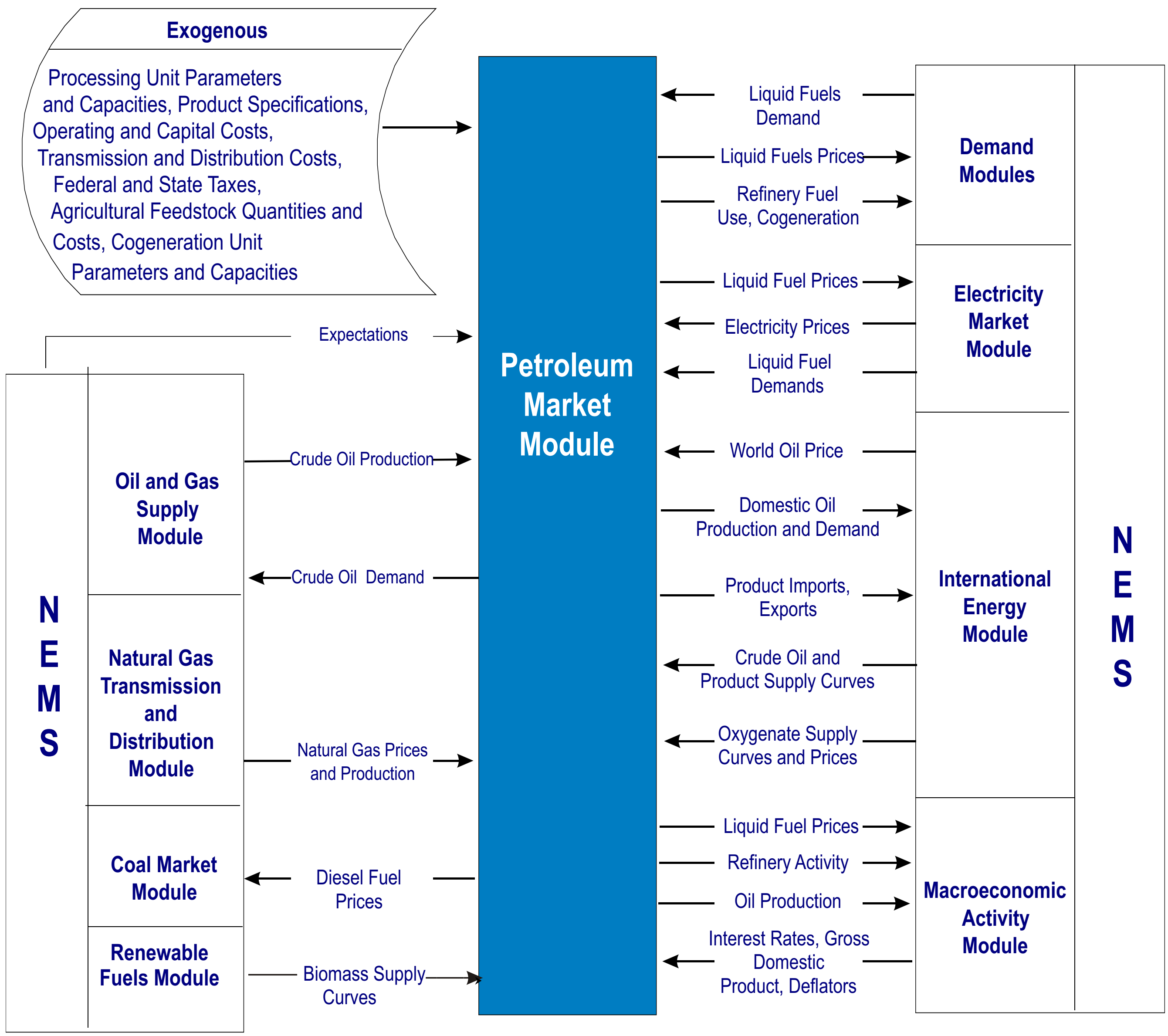
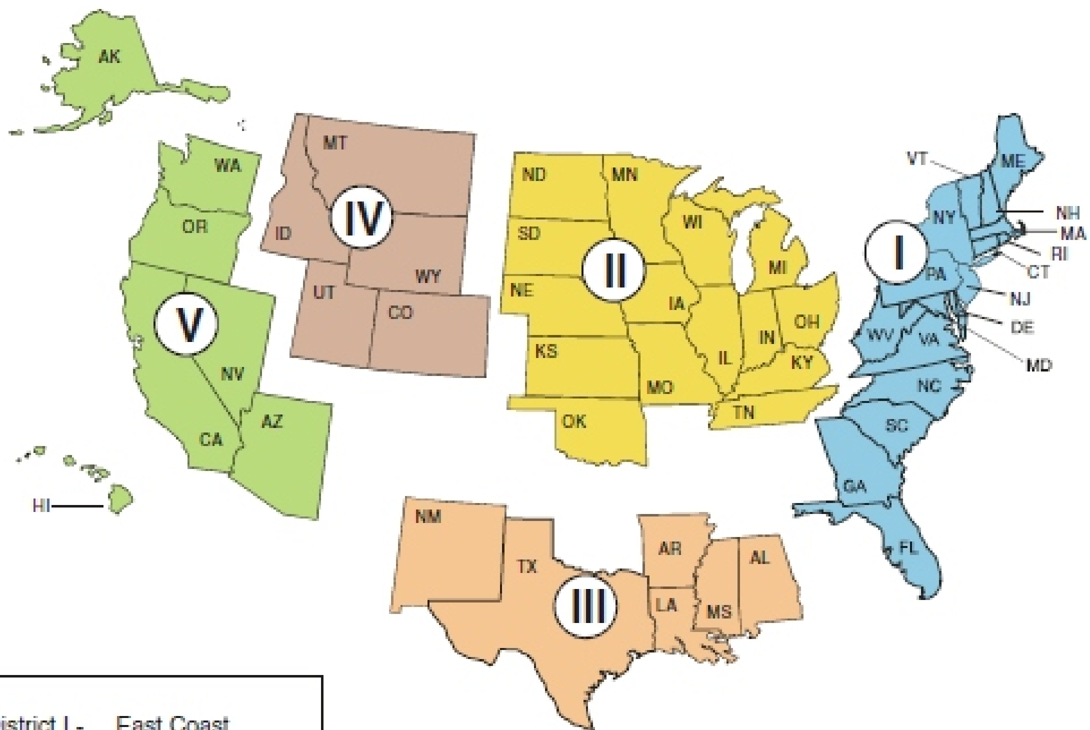


Figure 17. Petroleum Administration for Defense Districts



PAD District I - East Coast
PAD District II - Midwest
PAD District III - Gulf Coast
PAD District IV - Rocky Mountain
PAD District V - West Coast

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 CO_2.

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.

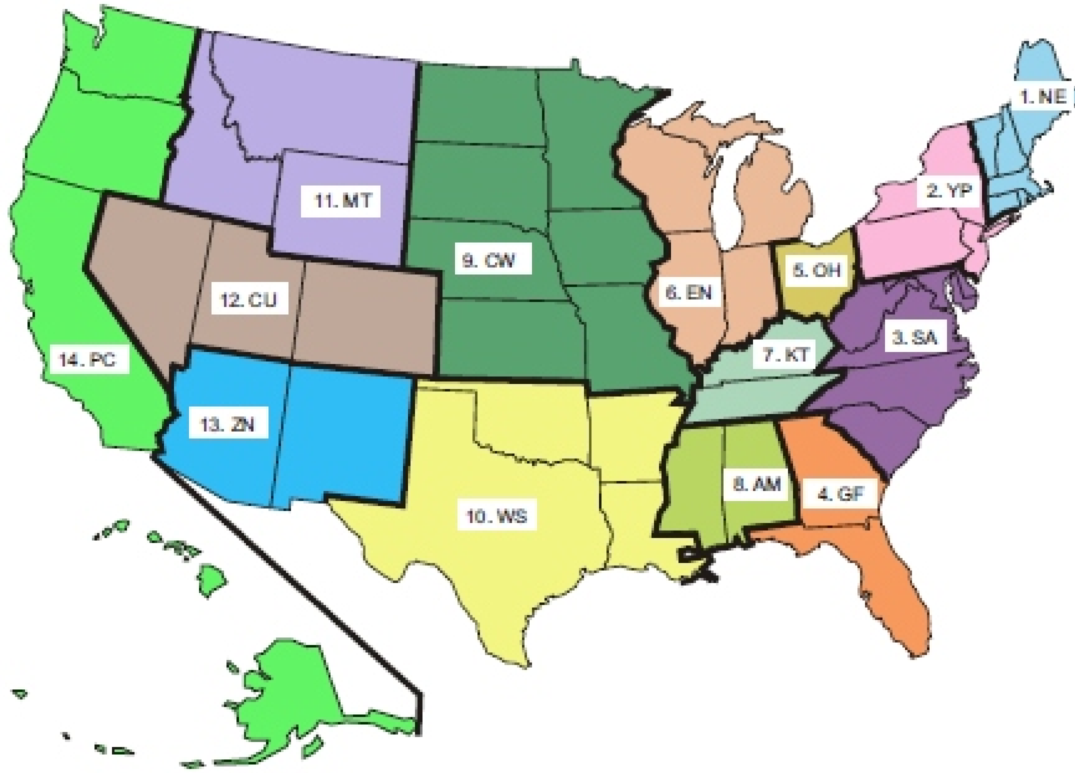
Coal transportation costs are simulated using interregional coal transportation costs derived by subtracting reported minemouth costs for each supply curve from reported delivered costs for each demand type in each demand region. For the electricity sector, higher transportation costs are assumed for 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.

Coal Market Module

Figure 19. Coal Market Module Supply Regions

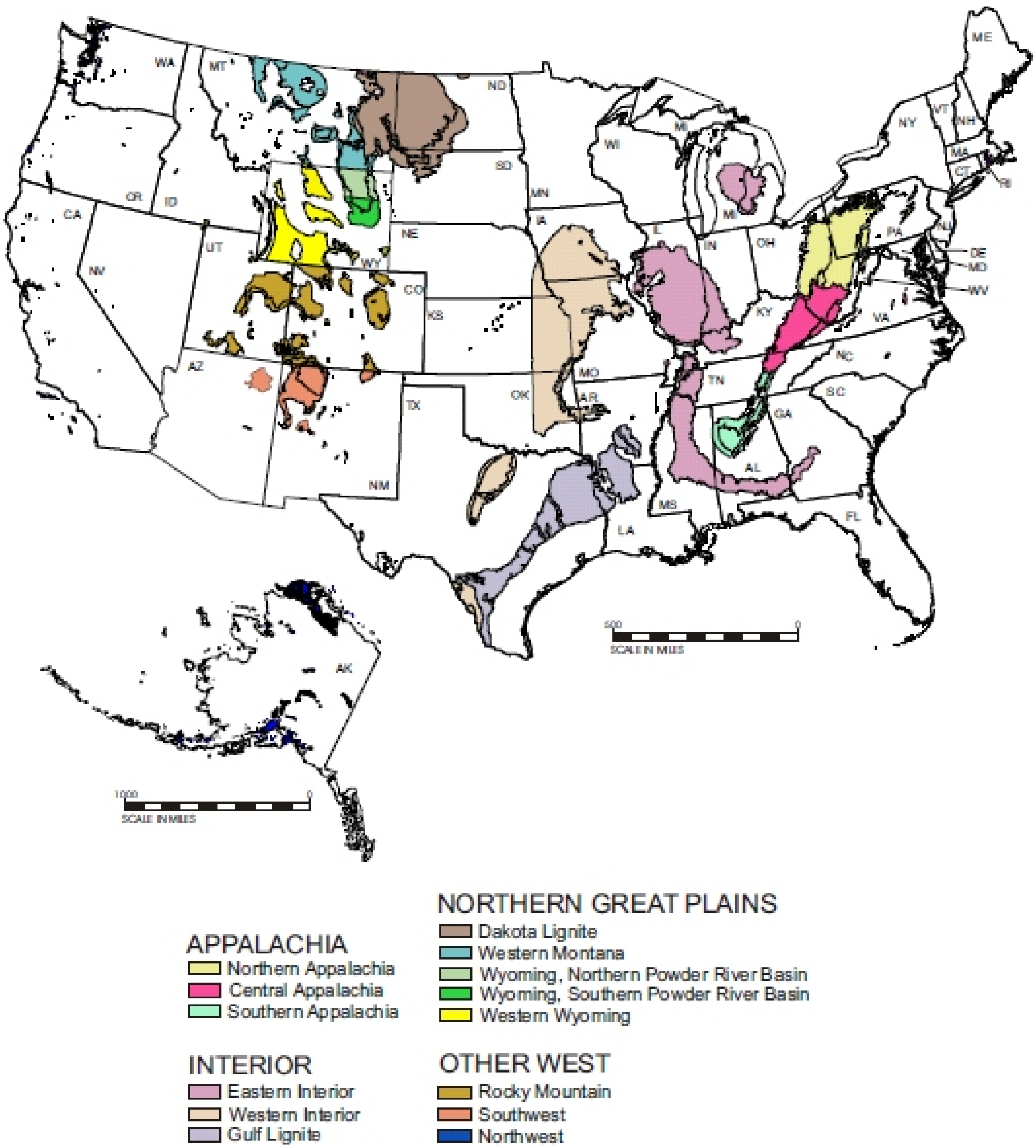
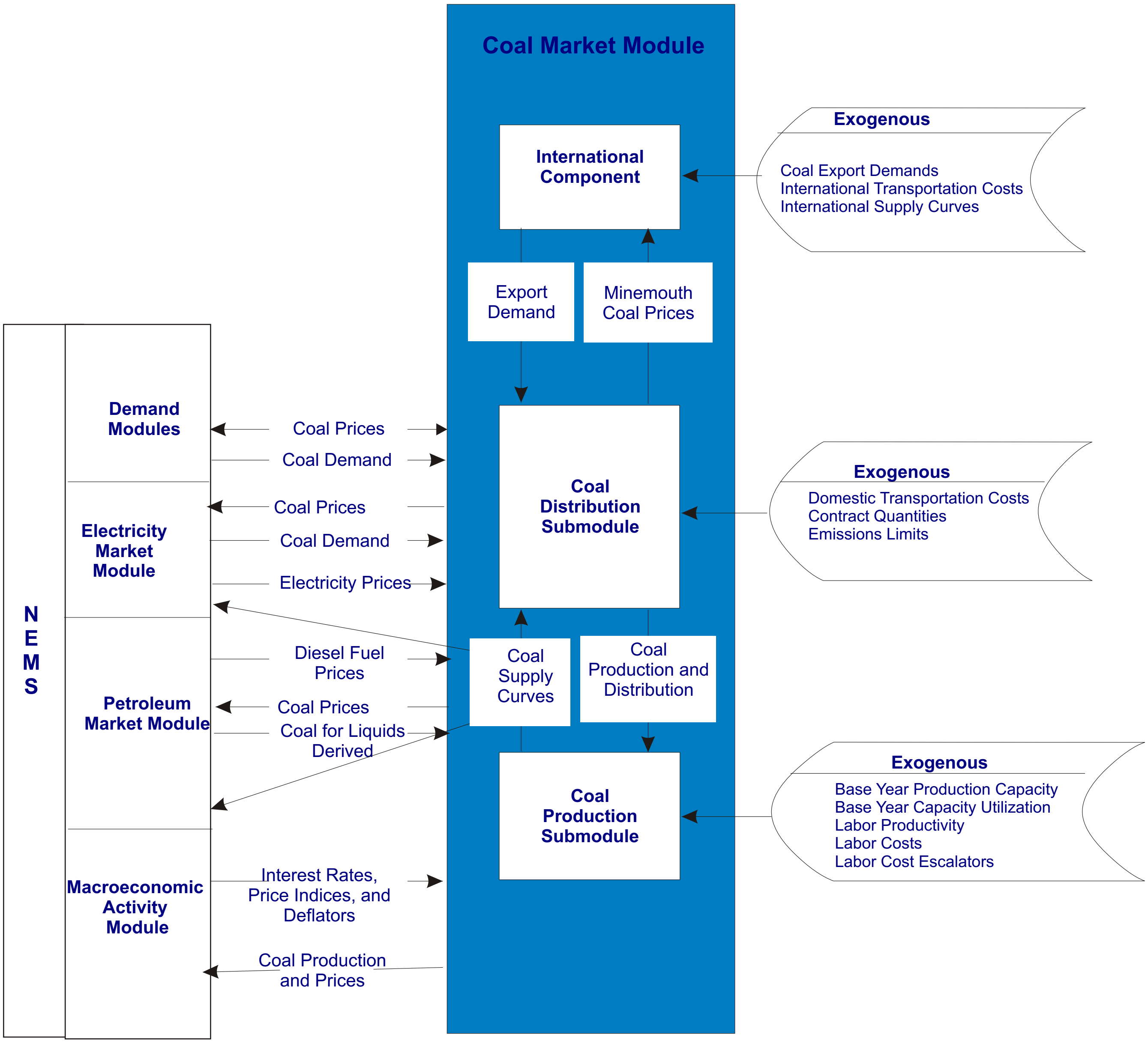


Table 13. Coal Export Component

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).

Energy Information Administration, *Integrating Module of the National Energy Modeling System: Model Documentation* DOE/EIA-M057(2009) (Washington, DC, May 2009).

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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

Contact Information

The Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System is developed and maintained by the U.S. Energy Information Administration (EIA), Office of Petroleum, Gas, and Biofuels Analysis. General questions about the use of the model can be addressed to Michael Schaal (202) 586-5590, Director of the Office of Petroleum, Gas, and Biofuels Analysis. Specific questions concerning the NGTDM may be addressed to:

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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.

Contents

Tables

Figures

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

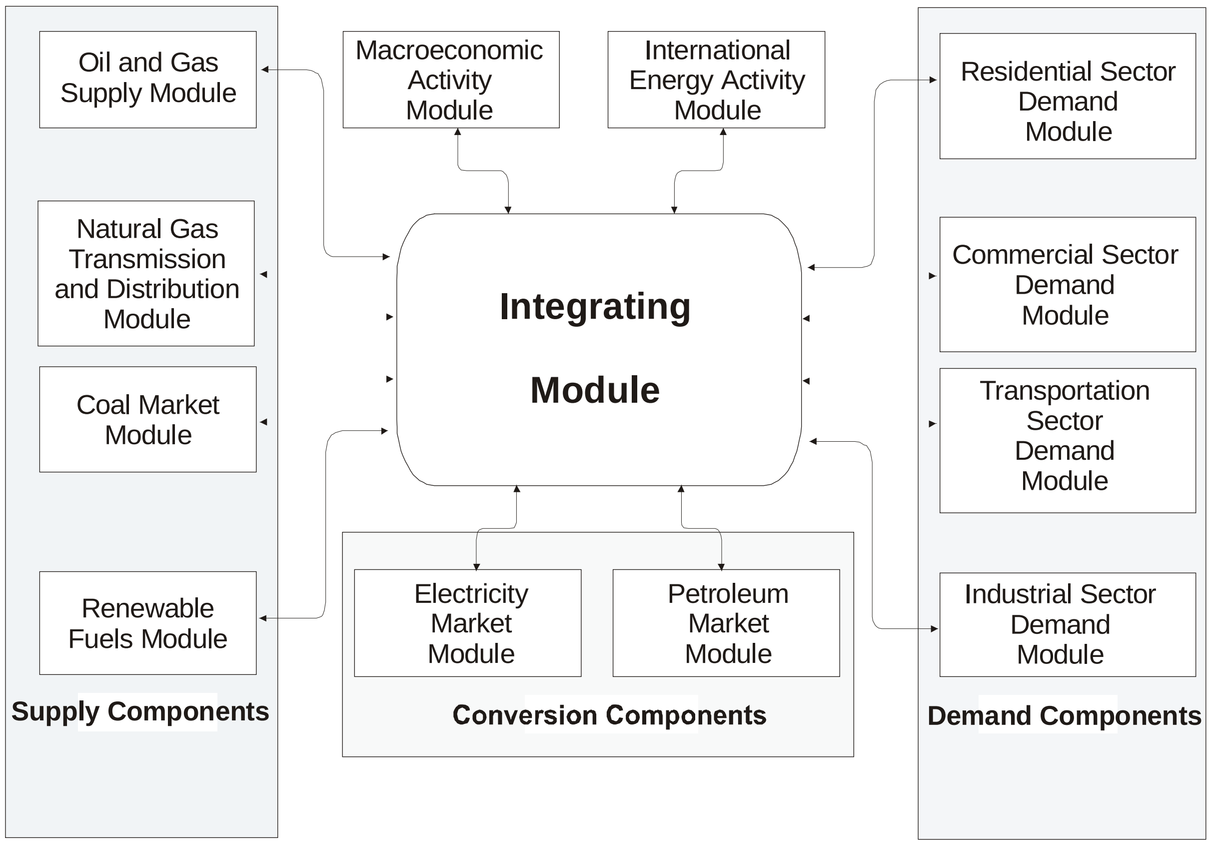
[1]Markets are said to be in equilibrium when the quantities demanded equal the quantities supplied at the same price; that is, at a price that sellers are willing to provide the commodity and consumers are willing to purchase the commodity.

[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

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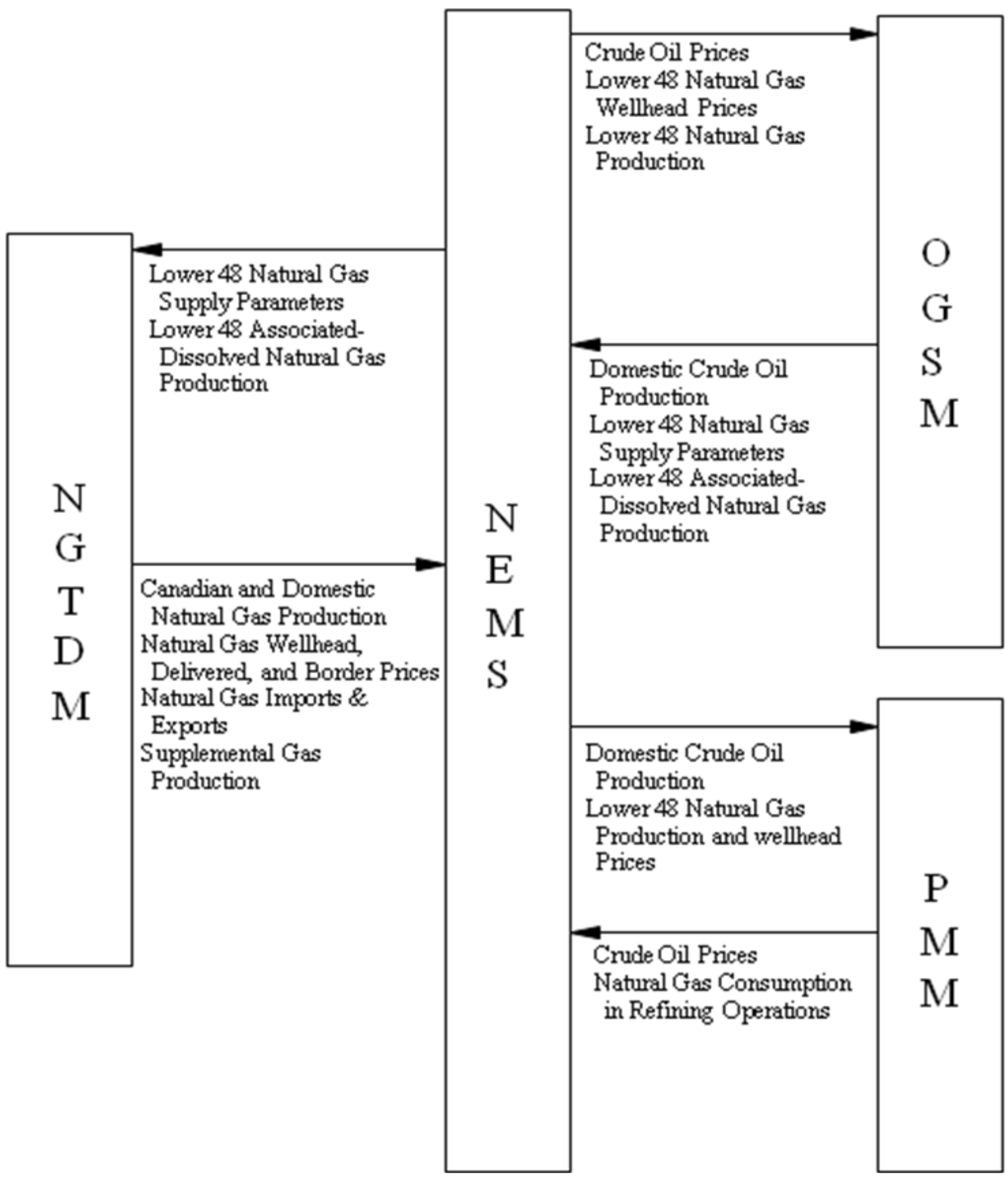
[7]A more detailed description of the NEMS system, including the convergence algorithm used, can be found in "Integrating Module of the National Energy Modeling System: Model Documentation 2010." DOE/EIA-M057(2010), May 2010 or "The National Energy Modeling System: An Overview 2009," DOE/EIA-0581(2009), 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.

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[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

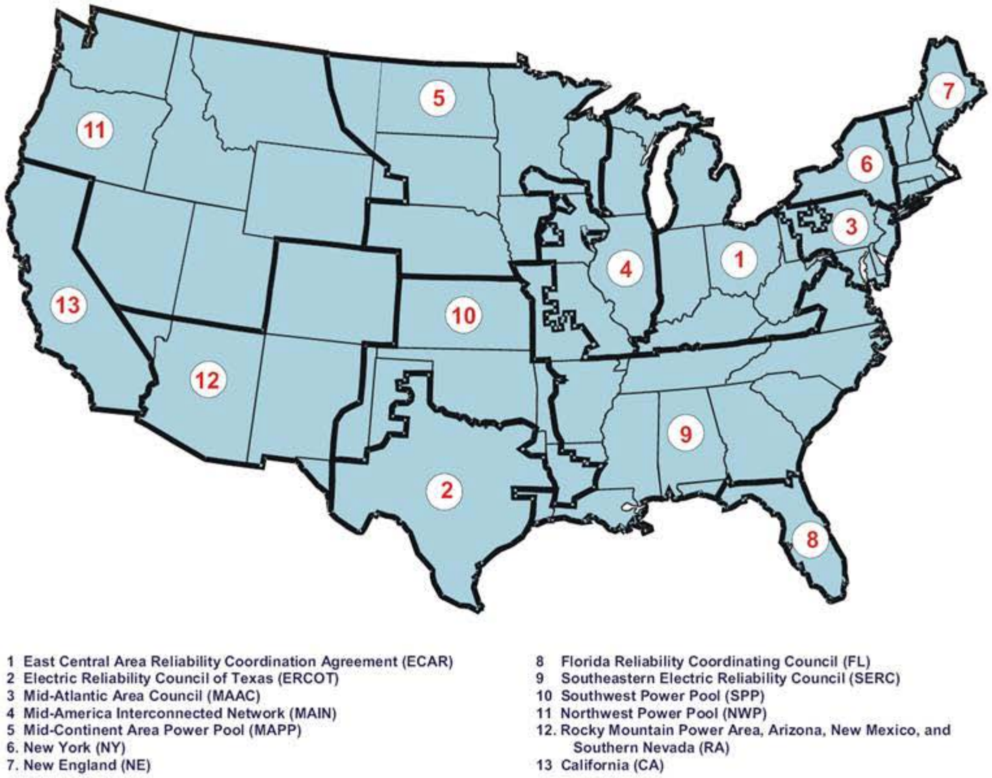
Natural gas consumption levels by all non-electric[16] sectors are provided by the NEMS demand modules for the nine Census divisions, the primary integrating regions represented in the NEMS. Alaska and Hawaii are included within the Pacific Census Division. The EMM represents the electricity generation 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).

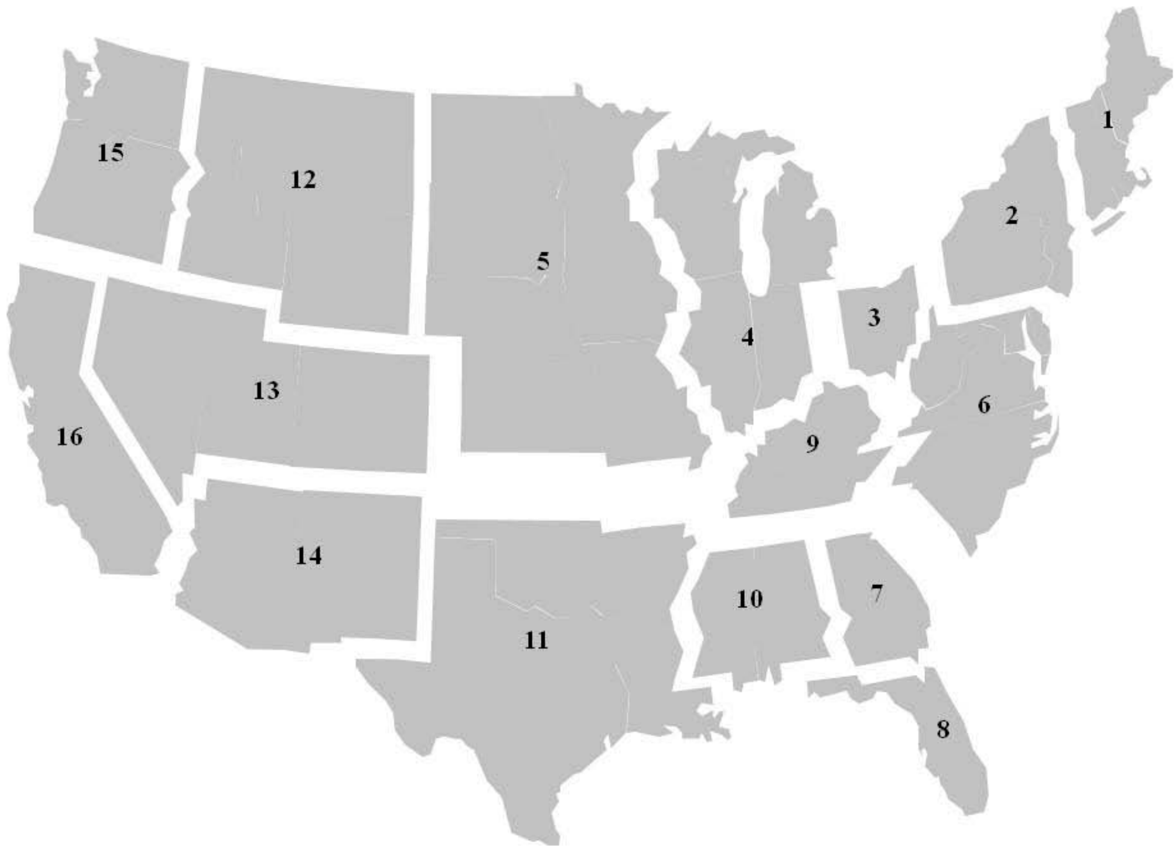
Figure 2-2. Electricity Market Module (EMM) Regions



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.

$$NGDMD\_CRVF_{s,r} = BASQTY\_F_{s,r} * (PR / BASPR\_F_{s,r})^{NONU\_ELAS\_F_s} \tag{1}$$

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

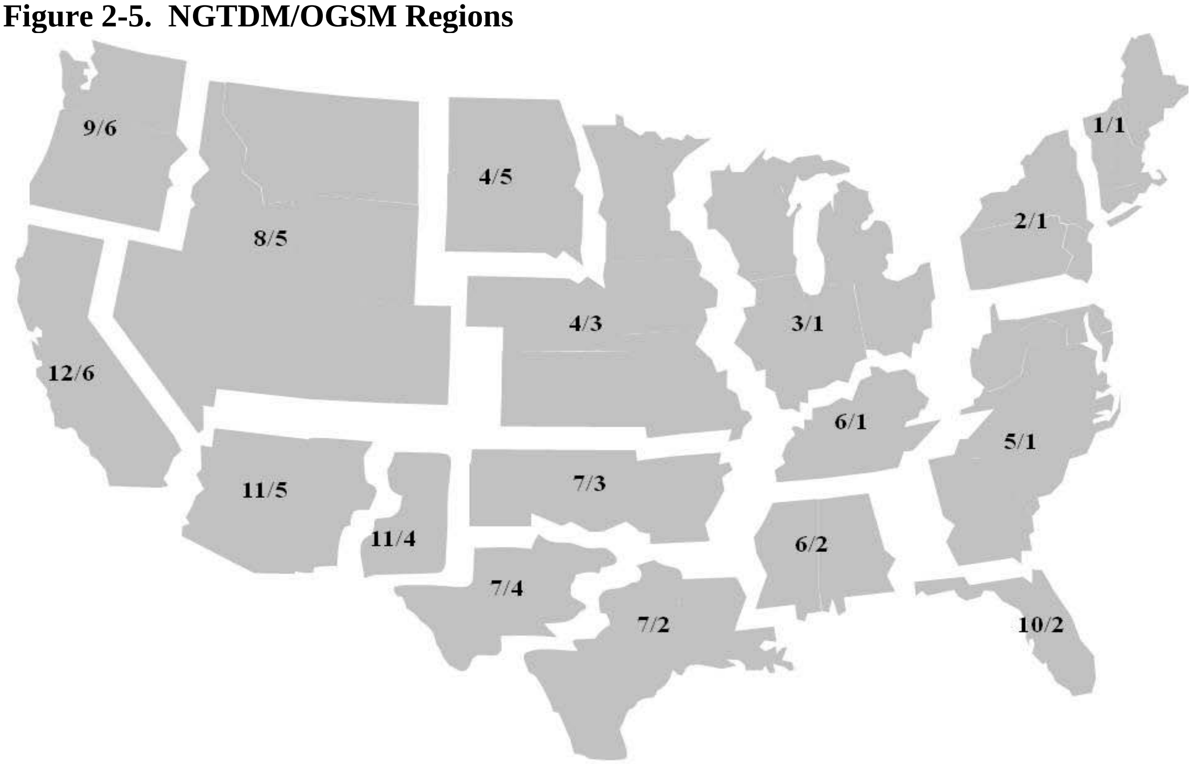
market equilibrium process in the NGTDM.

[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

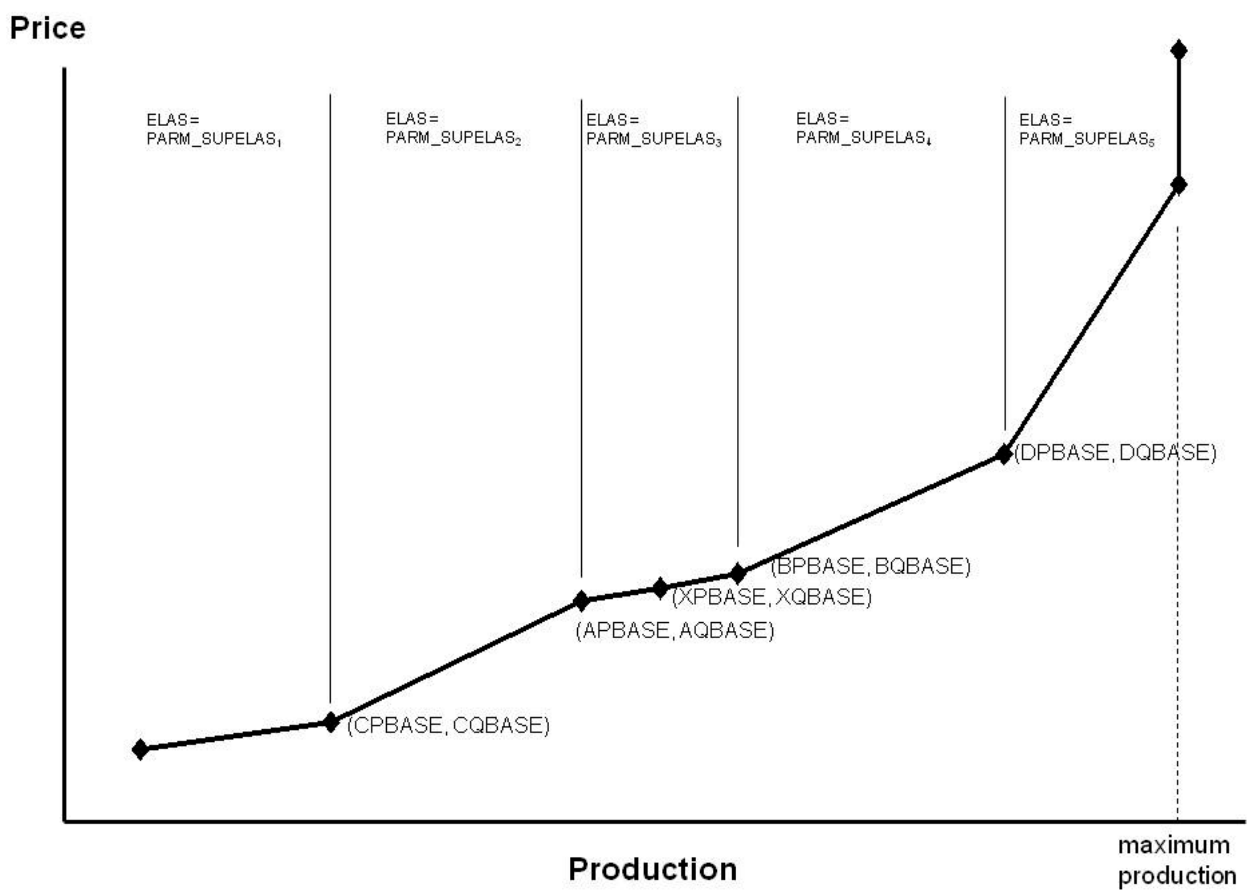
Figure 2-5. NGTDM/OGSM Regions



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:

$$\text{NGSUP\_PR} = \text{PBASE} * \left(\left(\left(\frac{1}{\text{ELAS}} \right) * \left(\frac{\text{QVAR - QBASE}}{\text{QBASE}} \right) \right) + 1 \right) \tag{2}$$

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:

$$\begin{aligned}\text{PBASE} = \text{CPBASE} = \text{APBASE} * (1- \\ (\text{PARM\_SUPCRV5}/\text{PARM\_SUPELAS2})\end{aligned} \quad (3)$$

$$\text{QBASE} = \text{CQBASE} = \text{AQBASE} * (1 - \text{PARM\_SUPCRV5}) \quad (4)$$

$$\text{ELAS} = \text{PARM\_SUPELAS1} = 0.40 \quad (5)$$

Lower segment:

$$\begin{aligned}\text{PBASE} = \text{APBASE} = \text{XPBASE} * \\ (1 - (\text{PARM\_SUPCRV3}/\text{PARM\_SUPELAS3}))\end{aligned} \quad (6)$$

$$\text{QBASE} = \text{AQBASE} = \text{XQBASE} * (1 - \text{PARM\_SUPCRV3}) \quad (7)$$

$$\text{ELAS} = \text{PARM\_SUPELAS2} = 0.35 \quad (8)$$

Middle segment:
(in historical years)

$$\text{PBASE} = \text{XPBASE} = \text{historical wellhead price} \quad (9)$$

$$\text{QBASE} = \text{XQBASE} = \text{QSUP}_s/(1 - \text{PERCNT}_n) \quad (10)$$

(in forecast years)

$$\text{PBASE} = \text{XPBASE} = \text{ZWPRLAG}_s \quad (11)$$

$$\text{QBASE} = \text{XQBASE} = \text{ZOGRESNG}_s * \text{ZOGPRRNG}_s \quad (12)$$

$$\text{ELAS} = \text{PARM\_SUPELAS3} = 1.00 \quad (13)$$

Upper segment:

$$\begin{aligned}\text{PBASE} = \text{BPBASE} = \text{XPBASE} * \\ (1 + (\text{PARM\_SUPCRV3}/\text{PARM\_SUPELAS3}))\end{aligned} \quad (14)$$

$$\text{QBASE} = \text{BQBASE} = \text{XQBASE} * (1 + \text{PARM\_SUPCRV3}) \quad (15)$$

$$\text{ELAS} = \text{PARM\_SUPELAS4} = 0.25 \quad (16)$$

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:

$$QVAR = (VALUE - FIXSUP) / (1.0 - PERCNT_n)$$

$$[\text{where,} \quad FIXSUP = ZOGCCAPPRD_s * (1.0 - PERCNT_n)]$$

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.

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[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:

$$\begin{aligned} \text{SUCWELL}_t &= \exp(-1.85639) * \text{CN\_PRC00}_t^{1.09939} * \text{URRCAN}_t^{1.57373} \\ &\quad * \text{CST\_PRXYLAG}^{-0.86063} * \exp(33.6237 * \text{CURPRRCAN}_{t\text{-}1}) \end{aligned} \tag{20}$$

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:

$$URRCAN_t = RESBASE * (1 + RESTECH)^T - CUMRCAN \tag{22}$$

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:

$$RESADCAN_t = FRCAN_t * SUCWELL_t \tag{23}$$

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.

$$RESBOYCAN_{t+1} = CURRESCAN_t + RESADCAN_t - OGPRDCAN_t \tag{24}$$

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:

$$PRRATCAN_t = \frac{e^{-72.1364+0.117911*\ln SUCWELL_t+0.041469*\ln FRCAN_t+0.03437*RLYR}}{1+e^{-72.1364+0.117911*\ln SUCWEL_t+0.041469*\ln FRCAN_t+0.03437*RLYR}} * \left(\frac{PRRATCAN_{t-1}}{1-PRRATCAN_{t-1}}\right)^{0.916835} * e^{-0.916835*(-72.1364+0.117911*\ln SUCWELL_{t-1}+0.041469*\ln FRCAN_{t-1}+0.03437*(RLYR-1))} \quad (25)$$

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

$$\mathrm{PRD2} = \mathrm{PARMA}*(\mathrm{PRDIYR} - \mathrm{PKIYR})^2 + \mathrm{PARMB} \tag{26}$$

area under the production function

$$\mathrm{CUR\_ULTRES} * \mathrm{PERRES}$$

$$\int_{\mathrm{LSTYR0}}^{\mathrm{PKIYR}} [\mathrm{PARMA} * (\mathrm{PRDIYR} - \mathrm{PKIYR})^2 + \mathrm{PARMB}]\, d\mathrm{PRDIYR} \tag{27}$$

production in year LSTYR0:

$$0 = \mathrm{PARMA}*(\mathrm{LSTYR0} - \mathrm{PKIYR})^2 + \mathrm{PARMB} \tag{28}$$

production in peak year when PRDIYR = PKIYR

$$\mathrm{PKPRD} = \mathrm{PARMA}*(\mathrm{PKIYR} - \mathrm{PKIYR})^2 + \mathrm{PARMB} = \mathrm{PARMB} \tag{29}$$

Derived from above:

$$\mathrm{PARMA} = \frac{-3}{2} * \frac{\mathrm{CUR\_ULTRES} * \mathrm{PERRES}}{(\mathrm{PKIYR} - \mathrm{LSTYRO})^3} \tag{30}$$

$$\mathrm{PARMB} = -\,\mathrm{PARMA}*(\mathrm{LSTYRO} - \mathrm{PKIYR})^2 \tag{31}$$

After Peak Production

Assumptions:

production function

$$\mathrm{PRD2} = (\mathrm{PARMC}*\mathrm{PRDIYR}) + \mathrm{PARMD} \tag{32}$$

area under the production function

$$\mathrm{CUR\_ULTRES}*(1 - \mathrm{PERRES}) = \int_{\mathrm{PKIYR}}^{\mathrm{LSTYR}} [(\mathrm{PARMC}*\mathrm{PRDIYR}) + \mathrm{PARMD}]\, d\mathrm{PRDIYR} \tag{33}$$

production in peak year when PRDIYR = PKIYR

$$\text{PKPRD} = \text{PARMB} = (\text{PARMC* PKIYR}) + \text{PARMD} \tag{34}$$

production in last year LSTYR

$$0 = (\text{PARMC*LSTYR}) + \text{PARMD} \tag{35}$$

Derived from above:

$$\text{PARMC} = \frac{-\text{PARMB}^2}{2\text{*CUR\_ULTRES*}(1-\text{PERRES})} \tag{36}$$

$$\text{LSTYR} = \frac{2\text{*CUR\_ULTRES*}(1-\text{PERRES})}{\text{PARMB}} + \text{PKIYR} \tag{37}$$

$$\text{PARMD} = -\text{PARMC*LSTYR} \tag{38}$$

given,

$$\text{CUR\_ULTRES} = \text{ULTRES*}(1+\text{RESTECH})^{(\text{MODYR}-\text{RESBASE})}\text{*}(1+\text{RESADJ}) \tag{39}$$

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.

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[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:

$$PRC\_FAC = MIN\left\{\left(\frac{OGWPRNG}{3.66}\right)^{0.03125} - 1, \quad 0.05\right\} \tag{40}$$

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:

$$AK\_RN_{y} = \exp\{-2.677 + (0.888 * \ln(AK\_RN_{y-1})) - (0.185 * \ln(AK\_RN_{y-2})) + (0.626 * \ln(AK\_POP_{y}))\} \tag{42}$$

$$AK\_CN_{y} = 0.932946 + (0.937471 * AK\_CN_{y-1}) \tag{43}$$

$$(res): AKQTY\_F_{s=1,y} = \{e^{(6.983794*(1-0.364042))} * (AKQTY\_F_{s=1,y-1} * 1000)^{0.364042} * * AK\_RN_{y}^{(0.601932*(1-0.364042))}\} / 1000. \tag{44}$$

$$(com): AKQTY\_F_{s=2,y} = \{e^{(9.425307*(1-0.736334))} * (AKQTY\_F_{s=2,y-1} * 1000)^{0.736334} * AK\_CN_{y}^{0.205020} * (AK\_CN_{y-1} * 1000)^{(-0.736334*0.205020)}\} / 1000. \tag{45}$$

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:

$$(ind): AKQTY\_F_{s=3,y} = AK\_QIND\_S_{y} \tag{46}$$

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:

$$\begin{aligned}(\mathrm{S.AK}):\ \mathrm{AK\_PROD}_{r=1} = {} & \mathrm{AK\_CONS\_S} + \mathrm{EXPJAP} + \mathrm{QALK\_LAP\_S} + \\ & \mathrm{QALK\_PIP\_S} - \mathrm{AK\_DISCR}\end{aligned} \tag{47}$$

$$\begin{aligned}(\mathrm{N.AK}_1):\ \mathrm{AK\_PROD}_{r=2} = \mathrm{QALK\_LAP\_N} = {} & (0.0943884 * \mathrm{QALK\_LAP\_NLAG} \\ & + (0.038873 * \textstyle\sum_{s=1}^{3} \mathrm{oOGPRCOAK}_{s,y})\end{aligned} \tag{48}$$

$$\begin{aligned}(\mathrm{N.AK}_2):\ \mathrm{AK\_PROD}_{r=3} = {} & \frac{\mathrm{QAK\_ALB}_y}{1. - \mathrm{AK\_PCTLSE}_{r=3} - \mathrm{AK\_PCTPLT}_{r=3} - \mathrm{AK\_PCTPIP}_{r=3}} + \\ & \mathrm{AKGTL\_NGCNS}_t + \mathrm{AKGTL\_LAP}\end{aligned} \tag{49}$$

where,

$$\mathrm{AK\_CONS\_S} = \sum_{s=1}^{4} (\mathrm{AKQTY\_F}_s + \mathrm{AKQTY\_I}_s) \tag{50}$$

$$\mathrm{QALK\_LAP\_S} = 0.0 \qquad \text{(total is assigned to the North)} \tag{51}$$

$$\mathrm{QALK\_PIP\_S} = (\mathrm{AK\_CONS\_S} + \mathrm{EXPJAP}) * \mathrm{AK\_PCTPIP}_2 \tag{52}$$

$$\mathrm{AKGTL\_LAP} = \mathrm{oAKGTL\_NGCNS}_t * (\mathrm{AK\_PCTLSE}_3 + \mathrm{AK\_PCTPLT}_3) \tag{53}$$

where,

$\mathrm{AK\_PROD}_r$	=	dry gas production in Alaska (Bcf)
AK_CONS_S	=	total gas delivered to customers in South Alaska (Bcf)
$\mathrm{AKQTY\_F}_s$	=	total gas delivered to core customers in Alaska in sector s (Bcf)
$\mathrm{AKQTY\_I}_s$	=	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.

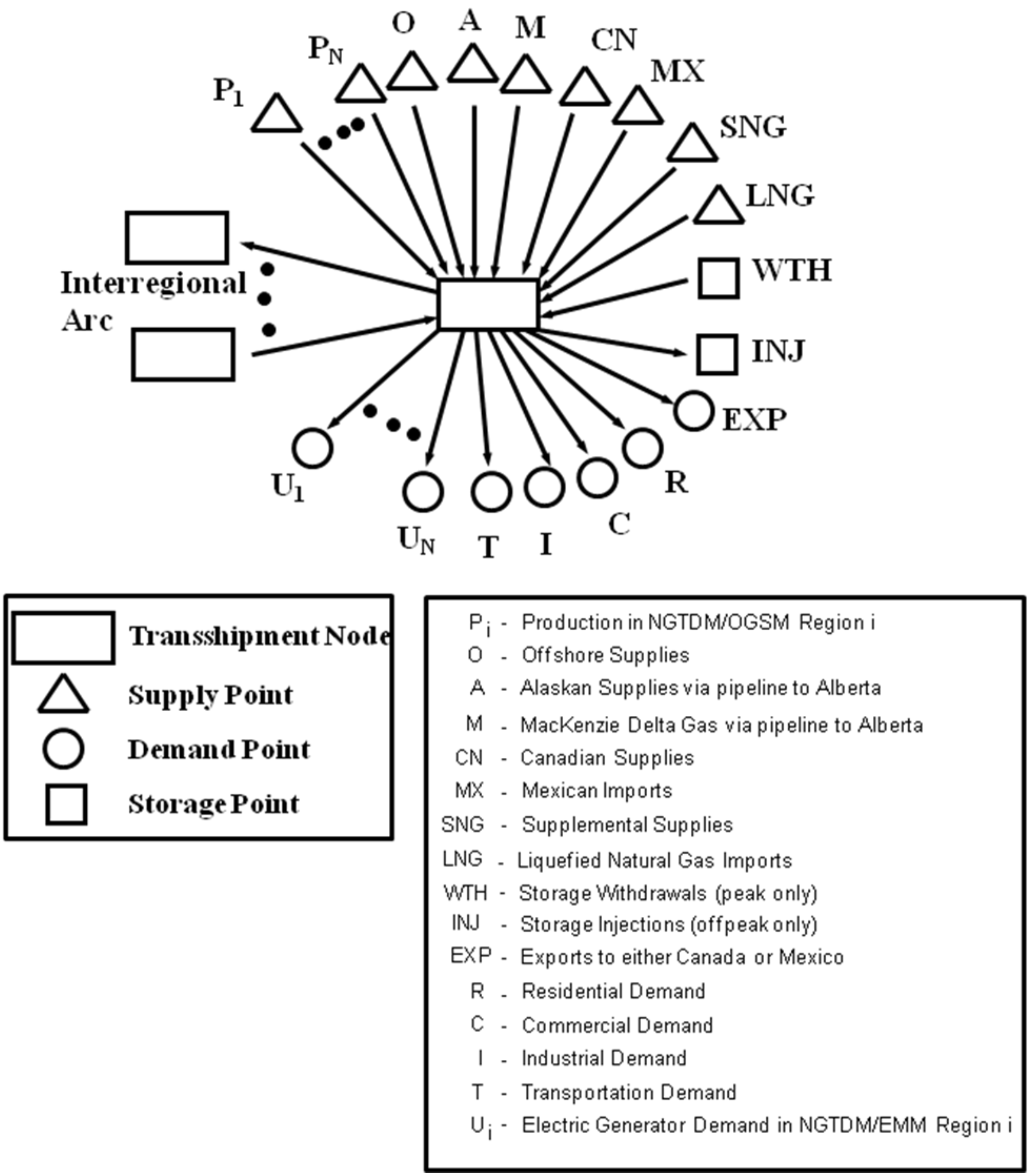
Figure 3-1. Natural Gas Transmission and Distribution Module Network

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

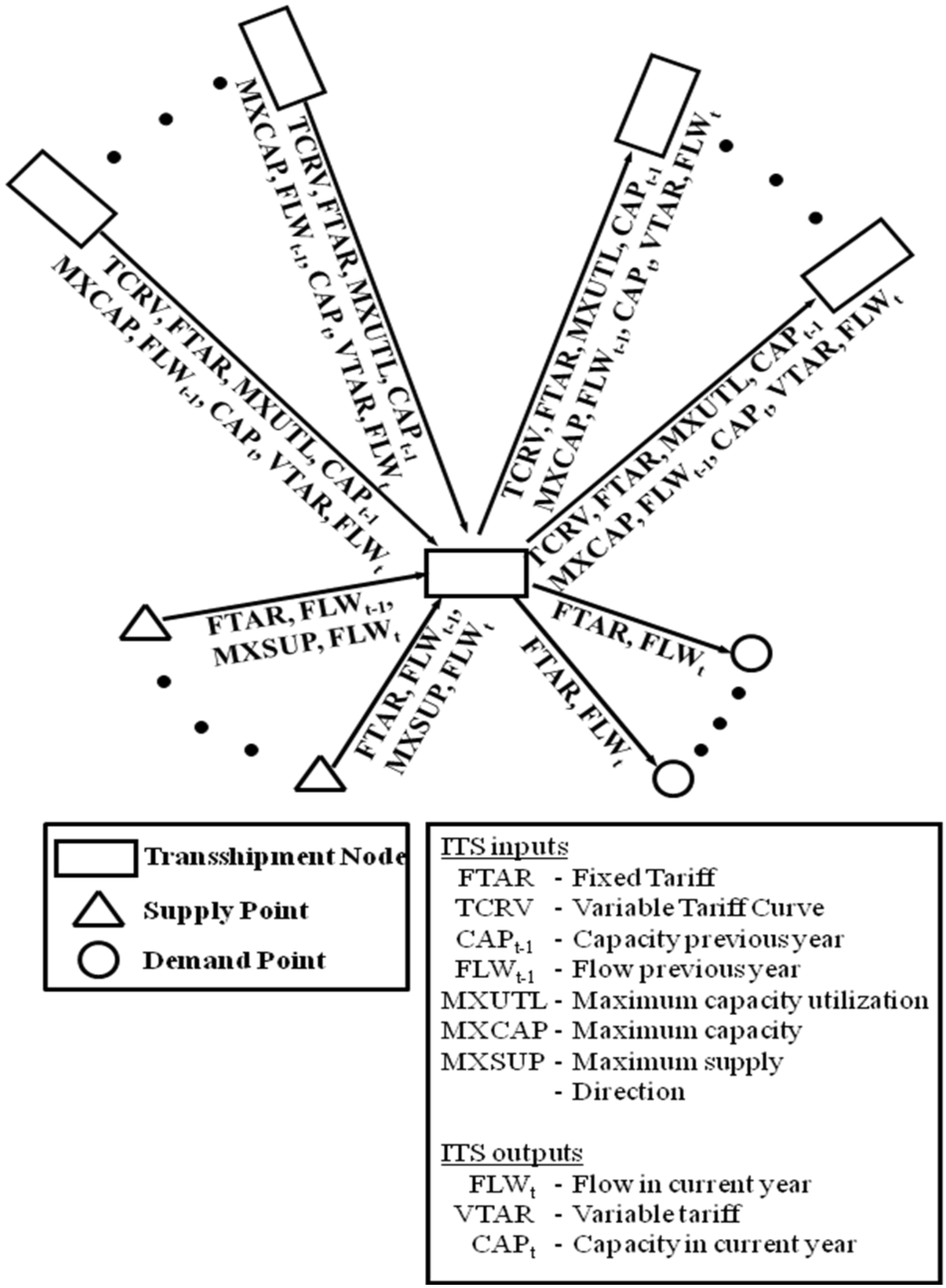
Transshipment Node	Demand Types	Supply Types
1	R, C, I, T, U(1)	P(1/1), LNG Everett Mass., LNG generic, SNG
2	R, C, I, T, U(2), INJ	P(2/1), WTH, LNG generic, SNG
3	R, C, I, T, U(3), U(4), INJ	P(3/1), WTH, SNG
4	R, C, I, T, U(5), INJ	P(4/3), P(4/5), SNG, WTH, LNG generic
5	R, C, I, T, U(6), U(7), INJ	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).

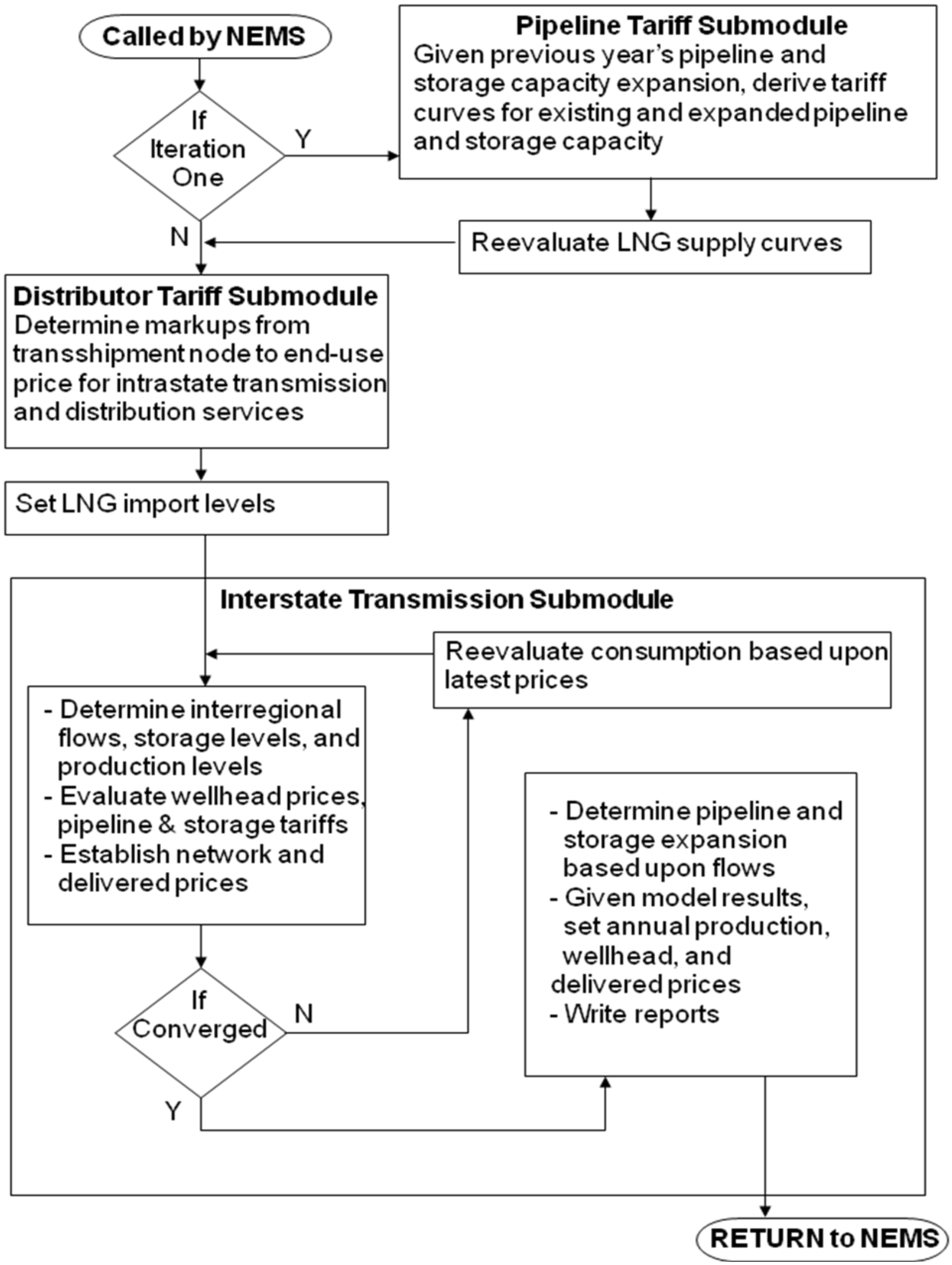
Although the NGTDM is executed for each iteration of each forecast year solved by the NEMS, it is not necessary that all of the individual components of the module be executed for all iterations. Of the NGTDM's three components or submodules, the Pipeline Tariff Submodule is executed only once per forecast 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



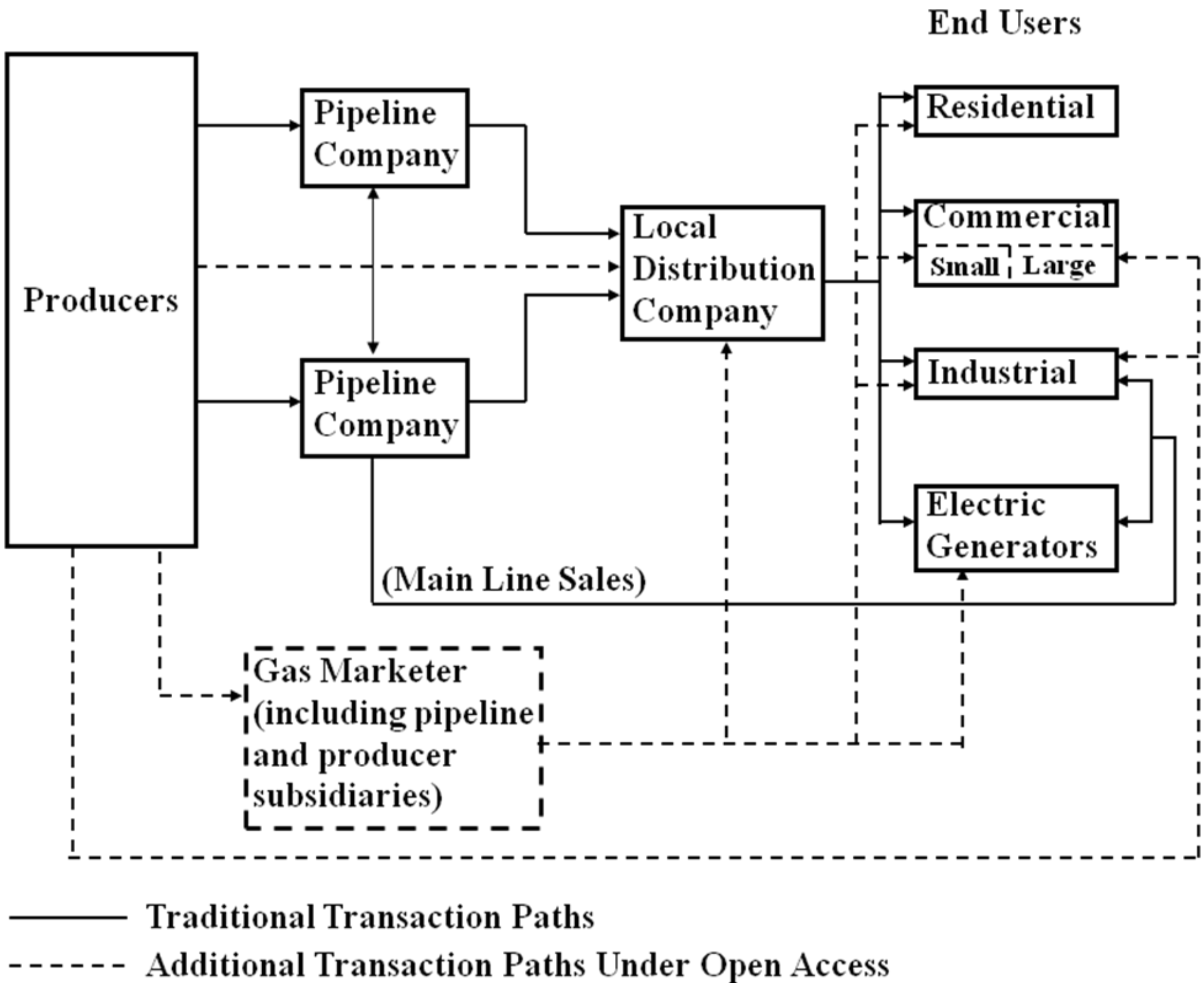
when (peak versus off-peak) it is needed. In the process, the ITS models the decision-making process for expanding pipeline and/or seasonal storage capacity in the U.S. gas market, determining the amount of pipeline and storage capacity to be added between or within regions in the NGTDM. Storage serves 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.

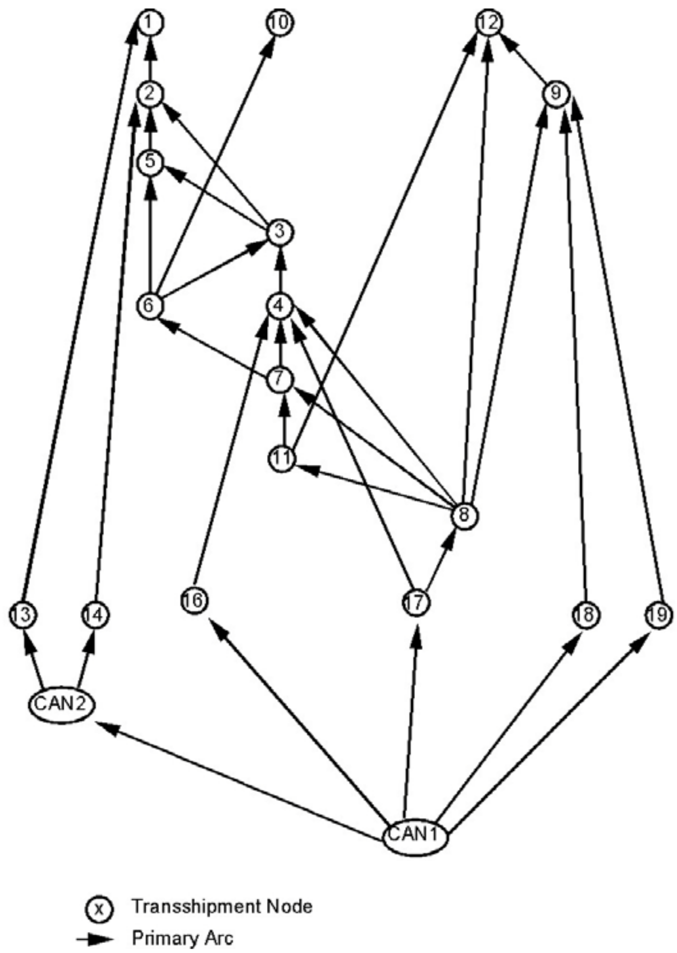
Network Characteristics in the ITS

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.

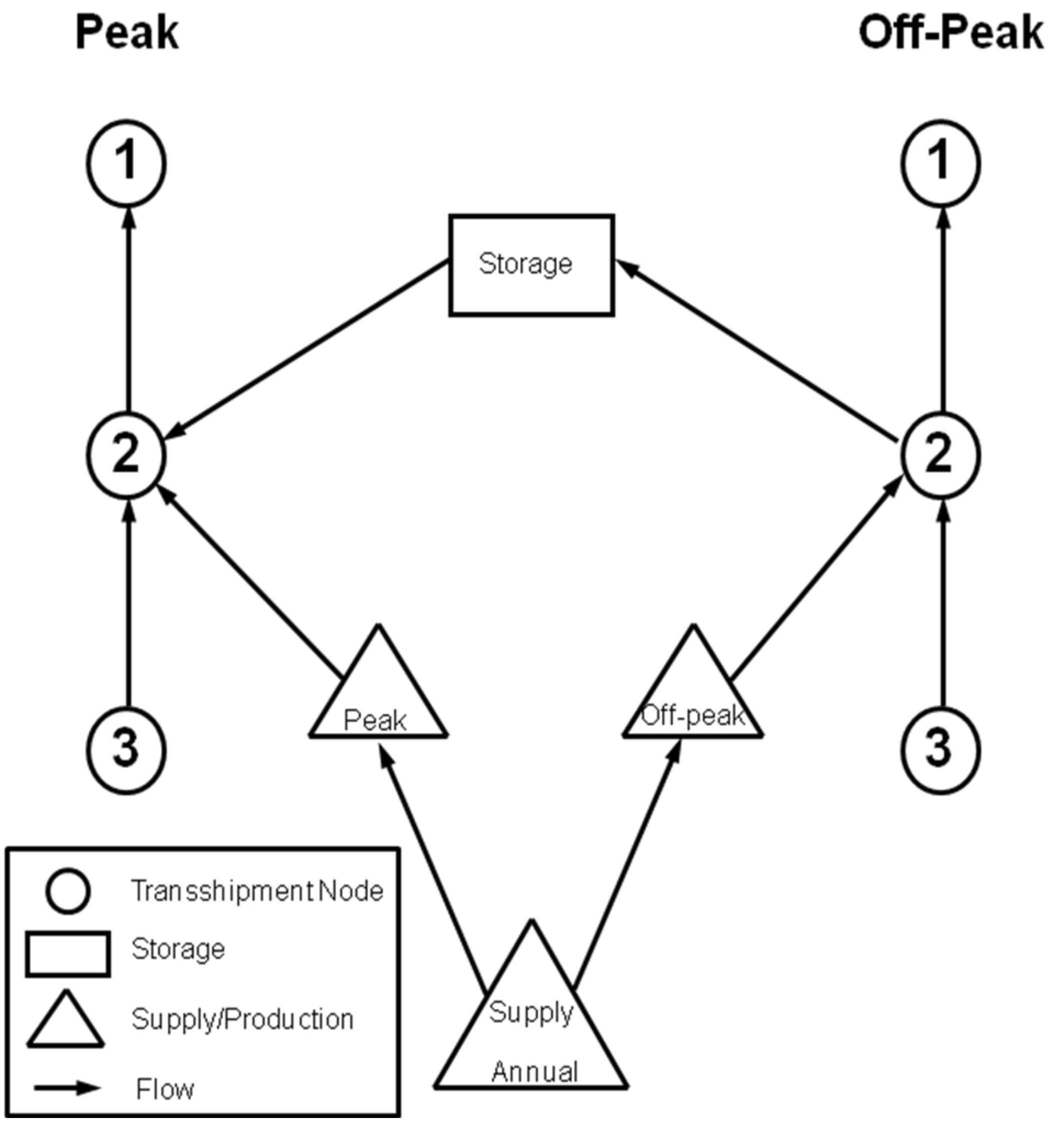
systematic representation of the flow of natural gas (and its associated prices) from the supply sources, represented towards the bottom of the network, up through the network to the end-use consumer at the upper end of the network.

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:

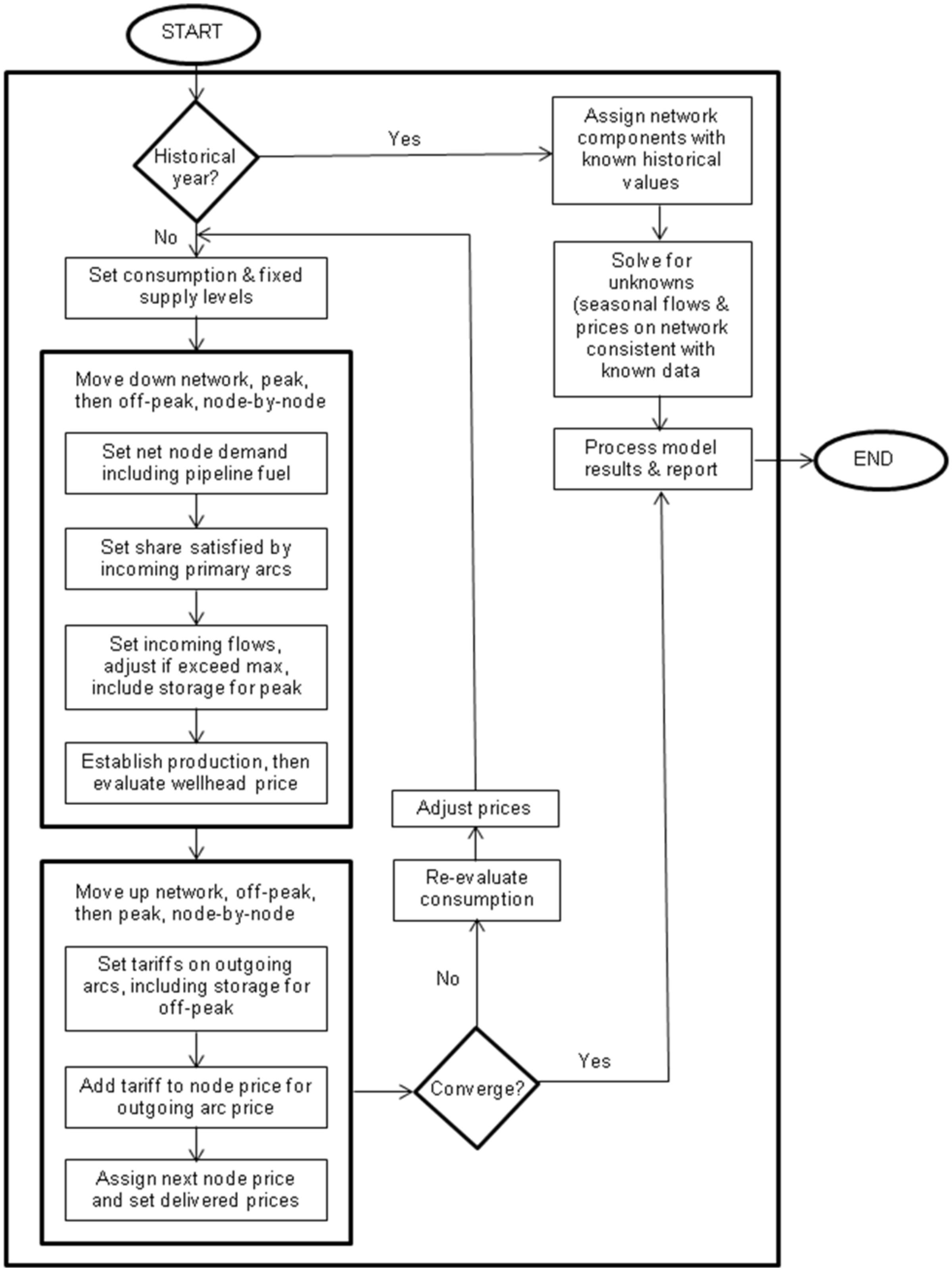
$$
\begin{aligned}
NODE\_DMD_{PK,r} = {} & PFUEL_{PK,r} + FLOW_{PK,a} + NODE\_CDMD_{PK,r} \\
& \sum_{nonu} (PKSHR\_DMD_{nonu,r} * (ZNGQTY\_F_{nonu,r} + ZNGQTY\_I_{nonu,r})) + \\
& \sum_{jutil \subset r} (PKSHR\_UDMD_{jutil} * (ZNGUQTY\_F_{jutil} + ZNGUQTY\_I_{jutil})
\end{aligned} \tag{55}
$$

$$
\begin{aligned}
NODE\_CDMD_{PK,r} = {} & YEAR\_CDMD_{PK,r} - (PKSHR\_PROD_{s} * ZADGPRD_{s}) - \\
& (PKSHR\_ILNG * OGQNGIMP_{L,t})
\end{aligned} \tag{56}
$$

$$
\begin{aligned}
YEAR\_CDMD_{PK,r} = {} & DISCR_{PK,r,t} + CN\_DISCR_{PK,cn} \\
& ((PKSHR\_CDMD) * CN\_DMD_{cn,r}) + \\
& (PK1 * SAFLOW_{a,t}) - (PK2 * SAFLOW_{a',t}) - \\
& (PKSHR\_YR * QAK\_ALB_{t}) - (PKSHR\_SUPLM * ZTOTSUP_{r}) - \\
& (PKSHR\_PROD_{s} * CN\_FIXSUP_{cn,t})
\end{aligned} \tag{57}
$$

[57] The model typically solves within 3 to 6 cycles.

Figure 4-3. Interstate Transmission Submodule System



Off-Peak:

$$\begin{aligned}&NODE\_DMD_{OP,r} = PFUEL_{OP,r} + FLOW_{OP,a} + FLOW_{PK,st} + NODE\_CDMD_{OP,r} + \\ &\sum_{nonu}((1 - PKSHR\_DMD_{nonu,r}) * (ZNGQTY\_F_{nonu,r} + ZNGQTY\_I_{nonu,r})) + \\ &\sum_{jutil \subset r}((1 - PKSHR\_UDMD_{jutil}) * (ZNGUQTY\_F_{jutil} + ZNGUQTY\_I_{jutil})) +\end{aligned} \tag{58}$$

$$\begin{aligned}&NODE\_CDMD_{OP,r} = YEAR\_CDMD_{OP,r} - ((1 - PKSHR\_PROD_s) * ZADGPRD_s) - \\ &((1 - PKSHR\_ILNG) * OGQNGIMP_{L,t})\end{aligned} \tag{59}$$

$$\begin{aligned}&YEAR\_CDMD_{OP,r} = DISCR_{OP,r,t} + CN\_DISCR_{OP,cn} + \\ &((1 - PKSHR\_CDMD) * CN\_DMD_{cn,r}) + \\ &((1 - PK1) * SAFLOW_{a,t}) - ((1 - PK2) * SAFLOW_{a',t}) - \\ &((1 - PKSHR\_YR) * QAK\_ALB_t) - \\ &((1 - PKSHR\_SUPLM) * ZTOTSUP_r) - \\ &((1 - PKSHR\_PROD_s) * CN\_FIXSUP_{cn,t})\end{aligned} \tag{60}$$

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:

$$PFUEL_{n,r} = PFUEL\_FAC_{n,r} * NODE\_DMD_{n,r} * SCALE\_PF \qquad (61)$$

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.

$$ARC\_PFUEL_{n,a} = (PFUEL_{n,r} - INTRA\_PFUEL_{n,r}) * \frac{FLOW_{n,a}}{TFLOW} \tag{62}$$

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:

$$FLO\_FAC_{n,r} = INTRA\_FLO_{n,r} \ / \ (NODE\_DMD_{n,r} - PFUEL_{n,r}) \tag{63}$$

Forecast of intraregional flow:

$$INTRA\_FLO_{n,r} = FLO\_FAC_{n,r} * (NODE\_DMD_{n,r} - PFUEL_{n,r}) \tag{64}$$

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:

$$SHR_{n,a,t} = \frac{ARC\_SHRPR_{n,a}^{-\gamma}}{\frac{\sum_{b} ARC\_SHRPR_{n,b}^{-\gamma}}{N}} * SHR_{n,a,t-1} \qquad (65)$$

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]

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[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:

$$FLOW_{n,a} = SHR_{n,a,t} * NODE\_DMD_{n,r} \tag{66}$$

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):

$$MAXFLO_{PK,a} = MAXPCAP_{PK,a} * (PKSHR\_YR * PKUTZ_a) \tag{67}$$

with $MAXPCAP_{PK,a}$ defined by type as follows:

for *Supply*[63]:

$$MAXPCAP_{PK,a} = ZOGRESNG_s * ZOGPRRNG_s * MAXPRRFAC * (1 - (PCTLP_r * SCALE\_LP_t)) \tag{68}$$

for *Pipeline*:

$$MAXPCAP_{PK,a} = PTMAXPCAP_{i,j} \tag{69}$$

for *Storage*:

$$MAXPCAP_{PK,a} = PTMAXPSTR_{st} \tag{70}$$

for *Canadian imports*:

$$MAXPCAP_{PK,a} = CURPCAP_{a,t} \tag{71}$$

Maximum off-peak pipeline flows:

$$MAXFLO_{OP,a} = MAXPCAP_{OP,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \tag{72}$$

with MAXPCAPOP,a is defined as follows for

either *current capacity:*

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} \tag{73}$$

or *current capacity* plus *capacity additions*,

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} + ((1 + XBLD) * (\frac{FLOW_{PK,a}}{PKSHR\_YR * PKUTZ_a} - CURPCAP_{a,t})) \tag{74}$$

or, for *pipeline arc entering region 10 (Florida), peak maximum capacity*,

$$MAXPCAP_{OP,a} = MAXPCAP_{PK,a} \tag{75}$$

[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:

$$MAXFLO_{OP,a} = MAXPCAP_{PK,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \qquad (76)$$

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):

$$ACTPCAP_a = \text{ MAX between } \frac{FLOW_{PK,a}}{PKSHR\_YR * PKUTZ_a} \text{ and } \frac{FLOW_{OP,a}}{(1 - PKSHR\_YR) * OPUTZ_a} \tag{79}$$

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:

$$MTHFLW_{n,a} = MTH\_NETNOD_{n,r} * \frac{SHR_{n,a,t}}{\sum_{c} SHR_{n,c,t}} \tag{80}$$

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:

$$MTH\_CAPADD_{n,a} = MTH\_TCAPADD_{n} * \frac{INIT\_CAPADD_{n,a}}{\sum_{c} INIT\_CAPADD_{n,c}} \tag{81}$$

[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:

$$ANNSUP = \frac{NODE\_QSUP_{PK,s}}{PKSHR\_YR} \tag{82}$$

Off-peak:

$$ANNSUP = \frac{NODE\_QSUP_{OP,s}}{(1 - PKSHR\_YR)} \tag{83}$$

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:

$$oOGHHPRNG_t = 1.00439 * e^{0.090246} * oOGWPRNG_{s=13,t}^{1.00119} \qquad (88)$$

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:

$$\begin{aligned} ARC\_ENDFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(n,a,i,j,FLOW_{n,a}) \\ ARC\_SHRFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(n,a,i,j,FLOW_{n,a}) \end{aligned} \tag{89}$$

Storage:

$$\begin{aligned} ARC\_SHRFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + X1NGSTR\_VARTAR(st,FLOW_{n,a}) \\ ARC\_ENDFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + X1NGSTR\_VARTAR(st,FLOW_{n,a}) \end{aligned} \tag{90}$$

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:

$$\begin{aligned} ARC\_SHRPR_{n,a} &= NODE\_SHRPR_{n,rs} + ARC\_SHRFEE_{n,a} \\ ARC\_ENDPR_{n,a} &= NODE\_ENDPR_{n,rs} + ARC\_ENDFEE_{n,a} \end{aligned} \tag{91}$$

with the adjustment accomplished through the assignment statements:

$$\begin{aligned} ARC\_SHRPR_{n,a} &= \frac{(ARC\_SHRPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})} \\ ARC\_ENDPR_{n,a} &= \frac{(ARC\_ENDPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})} \end{aligned} \tag{92}$$

[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:

$$NODE\_SHRPR_{n,rd} = \frac{\Sigma_a (ARC\_SHRPR_{n,a} * FLOW_{n,a})}{\Sigma_a (FLOW_{n,a} - ARC\_PFUEL_{n,a})}$$

$$NODE\_ENDPR_{n,rd} = \frac{\Sigma_a (ARC\_ENDPR_{n,a} * FLOW_{n,a})}{\Sigma_a (FLOW_{n,a} - ARC\_PFUEL_{n,a})} \qquad (93)$$

and,

$$NODE\_SHRPR_{n,rd} = \frac{(NODE\_SHRPR_{n,rd} * NODE\_DMD_{n,rd})}{(NODE\_DMD_{n,rd} - INTRA\_PFUEL_{n,rd})}$$

$$NODE\_ENDPR_{n,rd} = \frac{(NODE\_ENDPR_{n,rd} * NODE\_DMD_{n,rd})}{(NODE\_DMD_{n,rd} - INTRA\_PFUEL_{n,rd})} \qquad (94)$$

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:

$$NODE\_SHRPR_{PK,i} = NODE\_SHRPR_{OP,r}$$

$$NODE\_ENDPR_{PK,i} = NODE\_ENDPR_{OP,r} \tag{95}$$

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:

$$NODE\_SHRPR_{n,r} = NODE\_SHRPR_{n,r} + RBKSTOP\_PADJ_{n,r} \tag{96}$$

$$RBKSTOP\_PADJ_{n,r} = RBKSTOP\_PADJ_{n,r} + BKSTOP\_PADJ_{n,r} \tag{97}$$

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:

$$\begin{aligned} NODE\_QSUP_{n,s} = {} & (QSUP\_WT * NODE\_QSUP_{n,s}) + \\ & ((1 - QSUP\_WT) * NODE\_QSUPPREV_{n,s}) \end{aligned} \tag{98}$$

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:

$$\begin{aligned} CGPR_{n,r} = {} & NODE\_ENDPR_{n,r} + INTRAREG\_TAR_{n,r} + \\ & INTRAST\_TAR_{r} + CGBENCH_{n,r} \end{aligned} \tag{99}$$

such that:

$$CGBENCH_{n,r} = avg(HCG\_BENCH_{n,r,HISYR}) = avg(HCGPR_{n,r,HISYR} - CGPR_{n,r}) \tag{100}$$

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):

$$NGPR\_SF_{n,sec,r} = CGPR_{n,r} + DTAR\_SF_{n,sec,r} + SCALE\_FPR_{sec,t}$$

$$NGPR\_SI_{n,sec,r} = CGPR_{n,r} + DTAR\_SI_{n,sec,r} + SCALE\_IPR_{sec,t} \tag{101}$$

$$NGPR\_F_{sec,r} = NGPR\_SF_{PK,sec,r} * PKSHR\_DMD_{sec,r} + NGPR\_SF_{OP,sec,r} * (1.- PKSHR\_DMD_{sec,r})$$

$$NGPR\_I_{sec,r} = NGPR\_SI_{PK,sec,r} * PKSHR\_DMD_{sec,r} + NGPR\_SI_{OP,sec,r} * (1.- PKSHR\_DMD_{sec,r}) \tag{102}$$

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:

$$NGUPR\_SF_{n,j} = CGPR_{n,r} + UDTAR\_SF_{n,j} + SCALE\_FPR_{sec,t}$$

(103)

$$NGUPR\_SI_{n,j} = CGPR_{n,r} + UDTAR\_SI_{n,j} + SCALE\_IPR_{sec,t}$$

$$NGUPR\_F_{j} = NGUPR\_SF_{PK,j} * PKSHR\_UDMD_{j} + NGUPR\_SF_{OP,j} * (1. - PKSHR\_UDMD_{j})$$

(104)

$$NGUPR\_I_{j} = NGUPR\_SI_{PK,j} * PKSHR\_UDMD_{j} + NGUPR\_SI_{OP,j} * (1. - PKSHR\_UDMD_{j})$$

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:

$$NGPR\_TRPV\_SF_{n,r} = CGPR_{n,r} + DTAR\_TRPV\_SF_{n,r} + SCALE\_FPR_{sec,t}$$

$$NGPR\_TRFV\_SF_{n,r} = CGPR_{n,r} + DTAR\_TRFV\_SF_{n,r} + SCALE\_FPR_{sec,t} \tag{105}$$

$$NGPR\_TRPV\_F_{r} = NGPR\_TRPV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + NGPR\_TRPV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r})$$

$$NGPR\_TRFV\_F_{r} = NGPR\_TRFV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + NGPR\_TRFV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r}) \tag{106}$$

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

$$\text{DTAR\_SF}_{s=1,r,n=1} = e^{\text{PRSREGPK19}_{r,n=1}} * \text{NUMRS}_{r,t}^{0.162972} * \left(\frac{\text{BASQTY\_SF}_{s=1,r,n=1} + \text{BASQTY\_SI}_{s=1,r,n=1}}{\text{NUMRS}_{r,t}}\right)^{-0.607267} * \tag{107}$$

$$\text{DTAR\_SFPREV}_{s=1,r,n=1}^{0.231296} * e^{(-0.231296*\text{PRSREGPK19}_{r,n=1})} * \text{NUMRS}_{r,t-1}^{-0.231296*0.162972} * \left(\frac{\text{BASQTY\_SFPREV}_{s=1,r,n=1} + \text{BASQTY\_SIPREV}_{s=1,r,n=1}}{\text{NUMRS}_{r,t-1}}\right)^{(-0.231296*-0.607267)}$$

Residential off-peak

$$\text{DTAR\_SF}_{s=1,r,n=2} = e^{\text{PRSREGPK19}_{r,n=2}} * \text{NUMRS}_{r,t}^{0.282301} * \left(\frac{\text{BASQTY\_SF}_{s=1,r,n=2} + \text{BASQTY\_SI}_{s=1,r,n=2}}{\text{NUMRS}_{r,t}}\right)^{-0.814968} * \tag{108}$$

$$\text{DTAR\_SFPREV}_{s=1,r,n=2}^{0.231296} * e^{(-0.202612*\text{PRSREGPK19}_{r,n=2})} * \text{NUMRS}_{r,t-1}^{-0.202612*0.282301} * \left(\frac{\text{BASQTY\_SFPREV}_{s=1,r,n=2} + \text{BASQTY\_SIPREV}_{s=1,r,n=2}}{\text{NUMRS}_{r,t-1}}\right)^{(-0.202612*-0.814968)}$$

Commercial peak

$$\text{DTAR\_SF}_{s=2,r,n=2} = e^{\text{PCMREGPK13}_{r,n=1}} * \text{FLRSPC12}_{r,t}^{0.218189} * \left(\frac{\text{BASQTY\_SF}_{s=2,r,n=1} + \text{BASQTY\_SI}_{s=2,r,n=1}}{\text{FLRSPC12}_{r,t}}\right)^{-0.217322} * \tag{109}$$

$$\text{DTAR\_SFPREV}_{s=2,r,n=1}^{0.284608} * e^{(-0.284608*\text{PCMREGPK13}_{r,n=1})} * \text{FLRSPC12}_{r,t-1}^{-0.284608*0.218189} \left(\frac{\text{BASQTY\_SFPREV}_{s=2,r,n=1} + \text{BASQTY\_SIPREV}_{s=2,r,n=1}}{\text{FLRSPC12}_{r,t-1}}\right)^{(-0.284608*-0.217322)}$$

Commercial off-peak

$$DTAR\_SF_{s=2,r,n=2} = e^{PCMREGPK13_{r,n=2}} * FLRSPC12_{r,t}^{0.530831} * \left(\frac{BASQTY\_SF_{s=2,r,n=2} + BASQTY\_SI_{s=2,r,n=2}}{FLRSPC12_{r,t}} \right)^{-0.613588} * DTAR\_SFPREV_{s=2,r,n=2}^{0.166956} * e^{(-0.166956*PCMREGPK13_{r,n=2})} * FLRSPC12_{r,t-1}^{-0.166956*0.53083} \left(\frac{BASQTY\_SFPREV_{s=2,r,n=2} + BASQTY\_SIPREV_{s=2,r,n=2}}{FLRSPC12_{r,t-1}} \right)^{(-0.166956*-0.613588)} \quad (110)$$

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:

$$\begin{aligned} DTAR\_TRFV\_SF_{n,r} = \{ & HDTAR\_SF_{n,s=4,r,EHISYR} \\ & * (1 - TRN\_DECL)^{YR-DECL}\} + RETAIL\_COST_2 \\ & + \frac{(STAX_r + FTAX)}{MC\_PCWGDP_t / MC\_PCWGDP_{87}} \end{aligned} \tag{119}$$

$$\begin{aligned} DTAR\_TRPV\_SF_{n,r} = \{ & HDTAR\_SF_{n,s=4,r,EHISYR} \\ & * (1 - TRN\_DECL)^{YR-DECL}\} + RETAIL\_COST_2 \\ & + CNG\_RETAIL\_MARKUP_r + \frac{(STAX_r + FTAX)}{MC\_PCWGDP_t / MC\_PCWGDP_{87}} \end{aligned} \tag{120}$$

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:

$$TOTPUMPS = NSTAT_r * (MAX\_CNG\_BUILD + CNGAVAIL_{t-1}) \tag{121}$$

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:

$$TEST\_MARKUP_r = minimum\{5.0, MAX\_CNGMARKUP\} \tag{122}$$

where,

$$\begin{aligned} MAX\_CNGMARKUP_r &= 0.75 * \{PMGTR_{r,t-1} - \\ &(PGFTRPV_{r,t-1} - CNG\_RETAIL\_MARKUP_r)\} \end{aligned} \tag{123}$$

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:

$$REVENUE = \sum_{n=1}^{CNG\_HRZ} \frac{TEST\_MARKUP_r * DEMAND * 1000000}{TOTPUMPS * (1 + CNG\_WACC)^n} \tag{124}$$

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:

$$CNGAVAIL_{r,t} = CNGAVAIL_{r,t-1} + MAX\_CNG\_BUILD \tag{125}$$

$$RET\_MARK_r = TEST\_MARKUP \tag{126}$$

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

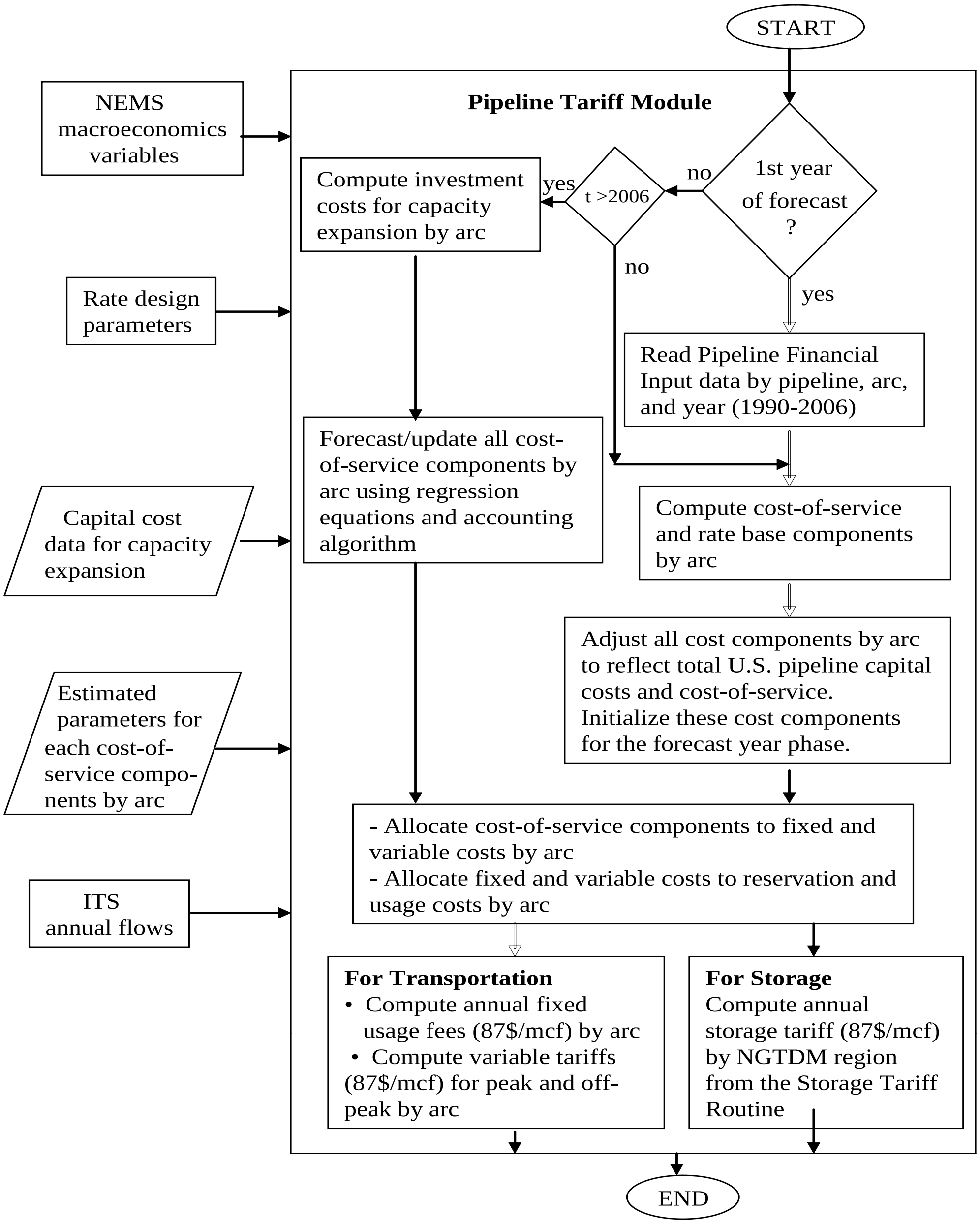
[83]Foster Financial Reports, 28 Major Interstate Natural Gas Pipelines, 2000, 2004 and 2007 Editions, Foster Associates, Inc., Bethesda, Maryland. The primary sources of data for these reports are FERC Form 2 and the monthly FERC Form 11 pipeline company filings. These reports can be purchased from 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:

$$TCOS_{a,t} = TRRB_{a,t} + TNOE_{a,t} \tag{127}$$

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:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \tag{128}$$

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 $APRB_{a,p,t}$.

$$TOTCAP_{a,p,t} = APRB_{a,p,t} \tag{136}$$

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:

$$\begin{aligned}
&PFES_{a,p,t} = GPFESTR_{a,p,t} * APRB_{a,p,t}\\
&CMES_{a,p,t} = GCMESTR_{a,p,t} * APRB_{a,p,t}\\
&LTDS_{a,p,t} = GLTDSTR_{a,p,t} * APRB_{a,p,t}\\
&GPFESTR_{a,p,t} + GCMESTR_{a,p,t} + GLTDSTR_{a,p,t} = 1.0
\end{aligned} \tag{137}$$

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:

$$WAROR_{a,t} = \sum_{p}[(PFES_{a,p,t} * PFER_{a,p,t} + CMES_{a,p,t} * CMER_{a,p,t} + LTDS_{a,p,t} * LTDR_{a,p,t})] / APRB_{a,t} \tag{138}$$

$$APRB_{a,t} = PFES_{a,t} + CMES_{a,t} + LTDS_{a,t} \tag{139}$$

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:

$$APRB_{a,p,t} = NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t} \tag{140}$$

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:

$$NPIS_{a,p,t} = GPIS_{a,p,t} - ADDA_{a,p,t} \tag{141}$$

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:

$$\begin{aligned} APRB_{a,,t} &= \sum_p APRB_{a,p,t} = \sum_p (NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t}) \\ &= (NPIS_{a,t} + CWC_{a,t} - ADIT_{a,t}) \end{aligned} \tag{142}$$

with,

$$\begin{aligned} NPIS_{a,,t} &= \sum_p (GPIS_{a,p,t} - ADDA_{a,p,t}) \\ &= (GPIS_{a,t} - ADDA_{a,t}) \end{aligned} \tag{143}$$

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:

$$TNOE_{a,t} = \sum_p (DDA_{a,p,t} + TOTAX_{a,p,t} + TOM_{a,p,t}) \tag{144}$$

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:

$$DDA_{a,t} = \sum_{p} DDA_{a,p,t} \tag{145}$$

$$TOM_{a,t} = \sum_{p} TOM_{a,p,t} \tag{146}$$

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:

$$TOTAX_{a,t} = \sum_{p} (FSIT_{a,p,t} + OTTAX_{a,p,t} + DIT_{a,p,t}) \tag{147}$$

$$FSIT_{a,t} = \sum_{p} FSIT_{a,p,t} = \sum_{p} (FIT_{a,p,t} + SIT_{a,p,t}) \tag{148}$$

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:

$$ATP_{a,t} = \sum_{p} (PFER_{a,p,t} * PFES_{a,p,t} + CMER_{a,p,t} * CMES_{a,p,t}) \tag{149}$$

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,

$$FIT_{a,t} = \frac{FRATE * ATP_{a,t}}{(1. - FRATE)} \tag{150}$$

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:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \tag{151}$$

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:

$$TOTAX_{a,t} = (FSIT_{a,t} + OTTAX_{a,t} + DIT_{a,t}) \tag{152}$$

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:

$$OTTAX_{a,t} = \sum_{p} OTTAX_{a,p,t} \tag{153}$$

$$DIT_{a,t} = \sum_{p} DIT_{a,p,t} \tag{154}$$

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,

$$\begin{aligned}
GPIS_{a,t} &= GPIS_{a,t} * HFAC_GPIS_t \\
ADDA_{a,t} &= ADDA_{a,t} * HFAC_GPIS_t \\
NPIS_{a,t} &= NPIS_{a,t} * HFAC_GPIS_t \\
CWC_{a,t} &= CWC_{a,t} * HFAC_GPIS_t \\
ADIT_{a,t} &= ADIT_{a,t} * HFAC_GPIS_t \\
APRB_{a,t} &= APRB_{a,t} * HFAC_GPIS_t
\end{aligned} \tag{155}$$

For the cost-of-service components,

$$\begin{aligned}
PFEN_{a,t} &= PFEN_{a,t} * HFAC_REV_t \\
CMEN_{a,t} &= CMEN_{a,t} * HFAC_REV_t \\
LTDN_{a,t} &= LTDN_{a,t} * HFAC_REV_t \\
DDA_{a,t} &= DDA_{a,t} * HFAC_REV_t \\
FSIT_{a,t} &= FSIT_{a,t} * HFAC_REV_t \\
OTTAX_{a,t} &= OTTAX_{a,t} * HFAC_REV_t \\
DIT_{a,t} &= DIT_{a,t} * HFAC_REV_t \\
TOM_{a,t} &= TOM_{a,t} * HFAC_REV_t
\end{aligned} \tag{156}$$

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:

$$FC_a = \sum_i R_{i,f} \tag{159}$$

$$VC_a = \sum_i R_{i,v} \tag{160}$$

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) Reservation	Usage	Cost Assigned to Rate Component (dollars) 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) Reservation	Usage	Cost Assigned to Rate Component (dollars) 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.

$$RCOST_a = \sum_i (R_{i,f,r} + R_{i,v,r}) \tag{165}$$

$$UCOST_a = \sum_i (R_{i,f,u} + R_{i,v,u}) \tag{166}$$

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:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA\_PIPE} \tag{167}$$

such that,

For peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * PKSHR\_YR}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{168}$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \tag{169}$$

For off-peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR\_YR)}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{170}$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \tag{171}$$

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:

$$\begin{aligned} FIXTAR_{a,t} = UCOST_{a,t} / [(&PKSHR\_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + \\ &(1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC\_PCWGDP_t] \end{aligned} \tag{172}$$

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,

$$PNOD_{r,t} = \frac{STCOS_{r,t}}{(MC\_PCWGDP_t * QNOD_{r,t} * 1{,}000{,}000.)} * STRATIO_{r,t} * STCAP\_ADJ_{r,t} * ADJ\_STR \quad (174)$$

$$QNOD_{r,t} = PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \quad (175)$$

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:

$$CCOST_{a,t} = AVG\_CAPCOST_a * MC\_PCWGDP_t / MC\_PCWGDP_{2000} \qquad (176)$$

[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:

$$NCAE_{a,t} = CCOST_{a,t} * CAPADD_{a,t} * 1{,}000{,}000 * (1 + PCNT\_R) \qquad (177)$$

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.

$$APRB_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} + CWC_{a,t} - ADIT_{a,t} \qquad (178)$$

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:

$$NPIS_{a,t} = NPIS\_E_{a,t} + NPIS\_N_{a,t} \tag{183}$$

$$NPIS\_E_{a,t} = GPIS\_E_{a,t} - ADDA\_E_{a,t-1} \tag{184}$$

$$NPIS\_N_{a,t} = GPIS\_N_{a,t} - ADDA\_N_{a,t-1} \tag{185}$$

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.

$$ADDA_{a,t} = ADDA_{a,t-1} + DDA_{a,t} \tag{186}$$

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.

$$DDA_{a,t} = DDA\_E_{a,t} + DDA\_N_{a,t} \tag{187}$$

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:

$$DDA\_E_{a,t} = \beta_{0,a} + \beta_1 * NPIS\_E_{a,t-1} + \beta_2 * NEWCAP\_E_{a,t} \tag{188}$$

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:

$$DDA\_N_{a,t} = GPIS\_N_{a,t} / 30 \tag{189}$$

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:

$$PFER_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_PFER_a \tag{192}$$

$$CMER_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_CMER_a \tag{193}$$

$$LTDR_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_LTDR_a \tag{194}$$

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:

$$TOTCAP_{a,t} = APRB_{a,t} \tag{201}$$

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:

$$\begin{aligned} PFES_{a,t} &= GPFESTR_a * APRB_{a,t} \\ CMES_{a,t} &= GCMESTR_a * APRB_{a,t} \\ LTDS_{a,t} &= GLTDSTR_a * APRB_{a,t} \end{aligned} \tag{202}$$

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).

$$GPFESTR_a = \frac{\sum_{t=1997}^{2006} \sum_p (GPFESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_p APRB_{a,p,t}} \tag{203}$$

$$GCMESTR_a = \frac{\sum_{t=1997}^{2006} \sum_p (GCMESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_p APRB_{a,p,t}} \tag{204}$$

$$GLTDSTR_a = \frac{\sum_{t=1997}^{2006} \sum_p (GLTDSTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_p APRB_{a,p,t}} \tag{205}$$

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:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \qquad (208)$$

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:

$$PFEN_{a,t} = GPFESTR_a * PFER_{a,t} * APRB_{a,t} \tag{209}$$

$$CMEN_{a,t} = GCMESTR_a * CMER_{a,t} * APRB_{a,t} \tag{210}$$

$$LTDN_{a,t} = GLTDSTR_a * LTDR_{a,t} * APRB_{a,t} \tag{211}$$

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:

$$TOTAX_{a,t} = FSIT_{a,t} + DIT_{a,t} + OTTAX_{a,t} \tag{212}$$

$$FSIT_{a,t} = FIT_{a,t} + SIT_{a,t} \tag{213}$$

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:

$$ATP_{a,t} = APRB_{a,t} * (PFER_{a,t} * GPFESTR_{a} + CMER_{a,t} * GCMESTR_{a}) \tag{214}$$

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:

$$FIT_{a,t} = (FRATE * ATP_{a,t} / 1. - FRATE) \tag{215}$$

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:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \tag{216}$$

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.

$$DIT_{a,t} = ADIT_{a,t} - ADIT_{a,t-1} \tag{217}$$

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.

$$OTTAX_{a,t} = OTTAX_{a,t-1} * EXPFAC_{a,t} * (MC\_PCWGDP_t / MC\_PCWGDP_{t-1}) \tag{218}$$

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:

$$EXPFAC_{a,t} = PTCURPCAP_{a,t} / PTCURPCAP_{a,t-1} \tag{219}$$

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:

$$R\_TOM_{a,t} = TOM\_K * e^{(\beta_{0,a} * (1-\rho) + G2 + G3 + G4 + G5 + G6 - \rho * (G7 + G8 + G4 + G9))} \tag{220}$$

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:

$$TOM_{a,t} = R\_TOM_{a,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{2000}} \qquad (221)$$

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:

$$FC_{a,t} = \sum_i (\xi_i * Item_{i,a,t}) \qquad (222)$$

$$VC_{a,t} = \sum_i [(1.0 - \xi_i) * Item_{i,a,t}] \qquad (223)$$

$$TCOS_{a,t} = FC_{a,t} + VC_{a,t} \qquad (224)$$

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:

$$RFC_{a,t} = \sum_i (\lambda_i * \xi_i * Item_{i,a,t}) \tag{225}$$

$$UFC_{a,t} = \sum_i [(1.0 - \lambda_i) * \xi_i * Item_{i,a,t}] \tag{226}$$

$$RVC_{a,t} = \sum_i [\mu_i * (1.0 - \xi_i) * Item_{i,a,t}] \tag{227}$$

$$UVC_{a,t} = \sum_{i} [(1.0 - \mu_i) * (1.0 - \xi_i) * Item_{i,a,t}] \qquad (228)$$

$$TCOS_{a,t} = RFC_{a,t} + UFC_{a,t} + RVC_{a,t} + UVC_{a,t} \qquad (229)$$

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:

$$RCOST_{a,t} = (RFC_{a,t} + RVC_{a,t}) \qquad (230)$$

$$UCOST_{a,t} = (UFC_{a,t} + UVC_{a,t}) \qquad (231)$$

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:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA\_PIPE} \tag{232}$$

capacity expansion segment:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA2\_PIPE} \tag{233}$$

such that,

for peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * PKSHR\_YR}{(QNOD_{a,t} * MC\_PCWGDP_t)} \tag{234}$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \tag{235}$$

for off-peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR\_YR)}{(QNOD_{a,t} * MC\_PCWGDP_t)} \quad (236)$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \quad (237)$$

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:

$$\begin{aligned} FIXTAR_{a,t} = UCOST_{a,t} / [(&PKSHR\_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + \\ &(1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC\_PCWGDP_t] \end{aligned} \quad (238)$$

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:

$$\begin{aligned} NGPIPE\_VARTAR_{a,t} = {} & CNMAXTAR - [CNMAXTAR * (1.0 - 0.9) * 2.0] - \\ & [CNMAXTAR * (0.9 - CANUTIL_{a,t}) * 0.25] \end{aligned} \tag{239}$$

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:

$$\begin{aligned} NGPIPE\_VARTAR_{a,t} = {} & CNMAXTAR - \\ & [CNMAXTAR * (1.0 - CANUTIL_{a,t}) * 2.0] \end{aligned} \tag{240}$$

where,

$$CANUTIL_{a,t} = \frac{Q_{a,t}}{QNOD_{a,t}} \tag{241}$$

for peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * PKSHR\_YR * PTPKUTZ_{a,t} \tag{242}$$

for off-peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} \tag{243}$$

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:

$$STCOS_{r,t} = STBTOI_{r,t} + STDDA_{r,t} + STTOTAX_{r,t} + STTOM_{r,t} \qquad (244)$$

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.

$$STPFEN_{r,t} = STGPFESTR_{r} * STPFER_{r,t} * STAPRB_{r,t} \tag{246}$$

$$STCMEN_{r,t} = STGCMESTR_{r} * STCMER_{r,t} * STAPRB_{r,t} \tag{247}$$

$$STLTDN_{r,t} = STGLTDSTR_{r} * STLTDR_{r,t} * STAPRB_{r,t} \tag{248}$$

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:

$$STBTOI_{r,t} = (STPFEN_{r,t} + STCMEN_{r,t} + STLTDN_{r,t}) \tag{249}$$

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:

$$STWAROR_{r,t} = STPFER_{r,t} * STGPFESTR_{r} + STCMER_{r,t} * STGCMESTR_{r} + STLTDR_{r,t} * STGLTDSTR_{r} \tag{250}$$

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:

$$STPFER_{r,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_STPFER_r \quad (254)$$

$$STCMER_{r,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_STCMER_r \qquad (255)$$

$$STLTDR_{r,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_STLTDR_r \qquad (256)$$

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:

$$ADJ\_STLTDR_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STLTDN_{r,t}}{STLTDS_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \qquad (257)$$

$$ADJ\_STPFER_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STPFEN_{r,t}}{STPFES_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \qquad (258)$$

$$ADJ\_STCMER_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STCMEN_{r,t}}{STCMES_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \qquad (259)$$

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:

$$STAPRB_{r,t} = STNPIS_{r,t} + STCWC_{r,t} - STADIT_{r,t} \tag{260}$$

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:

$$STNPIS_{r,t} = STGPIS_{r,t} - STADDA_{r,t-1} \tag{261}$$

[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:

$$STGPIS_{r,t} = STGPIS\_E_{r,t} + STGPIS\_N_{r,t} \tag{262}$$

$$STNPIS_{r,t} = STNPIS\_E_{r,t} + STNPIS\_N_{r,t} \tag{263}$$

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:

$$STADDA_{r,t-1} = STADDA\_E_{r,t-1} + STADDA\_N_{r,t-1} \tag{264}$$

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:

$$STADDA\_E_{r,t} = STADDA\_E_{r,t-1} + STDDA\_E_{r,t} \tag{265}$$

$$STADDA\_N_{r,t} = STADDA\_N_{r,t-1} + STDDA\_N_{r,t} \tag{266}$$

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.

$$STADDA_{r,t} = STADDA_{r,t-1} + STDDA_{r,t} \tag{267}$$

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.

$$STDDA_{r,t} = STDDA\_E_{r,t} + STDDA\_N_{r,t} \tag{268}$$

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:

$$\begin{aligned} STADIT_{r,t} = {} & STADIT\_C + (STADIT\_ADIT * STADIT_{r,t-1}) + \\ & (STADIT\_NEWCAP * NEWCAP_{r,t}) \end{aligned} \tag{277}$$

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:

$$STTOTAX_{r,t} = STFSIT_{r,t} + STDIT_{r,t} + STOTTAX_{r,t} \tag{278}$$

$$STFSIT_{r,t} = STFIT_{r,t} + STSIT_{r,t} \tag{279}$$

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.

$$STDIT_{r,t} = STADIT_{r,t} - STADIT_{r,t-1} \tag{284}$$

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.

$$STOTTAX_{r,t} = STOTTAX_{r,t-1} * (MC\_PCWGDP_t / MC\_PCWGDP_{t-1}) \tag{285}$$

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:

$$R\_STTOM_{r,t} = e^{(STTOM\_C*(1-\rho))} * DSTWCAP_{r,t-1}^{STTOM\_WORKCAP} * R\_STTOM_{r,t-1}^{\rho} * DSTWCAP_{r,t-2}^{-\rho*STTOM\_WORKCAP} \tag{286}$$

[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.

$$STTOM_{r,t} = R\_STTOM_{r,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{1996}} \tag{287}$$

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:

$$PNOD_{r,t} = \frac{STCOS_{r,t}}{(MC\_PCWGDP_t * QNOD_{r,t} * 1{,}000{,}000.)} * STRATIO_{r,t} * STCAP\_ADJ_{r,t} * ADJ\_STR * (1.0 - STR\_EFF/100.)^t \tag{288}$$

where,

$$STCAP\_ADJ_{r,t} = \frac{PTCURPSTR_{r,t}}{FS\_PTCURPSTR_{r,t}} \tag{289}$$

$$QNOD_{r,t} = PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \tag{290}$$

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:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA\_STR} \tag{291}$$

capacity expansion segment:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA2\_STR} \tag{292}$$

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:

$$FR\_DDA_t = FR\_CAPITL1 / INVEST\_YR \tag{293}$$

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:

$$\begin{aligned} FR\_CAPITL1 = {} & FR\_CAPIT0 / FR\_PCNSYR \; * \\ & [(1+r) + (1+r)^2 + ... + (1+r)^{FR\_PCNSYR}] \end{aligned} \tag{294}$$

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:

$$\begin{aligned} & FR\_NPIS_t = FR\_GPIS_t - FR\_ADDA_t \\ & FR\_ADDA_t = FR\_ADDA_{t-1} + FR\_DDA_t \end{aligned} \tag{295}$$

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:

$$FR\_TRRB_t = WACC_t * FR\_NPIS_t \tag{296}$$

where,

$$WACC_t = FR\_DEBTRATIO * COST\_OF\_DEBT_t + (1.0 - FR\_DEBTRATIO) * COST\_OF\_EQUITY_t \tag{297}$$

and

$$COST\_OF\_DEBT_t = (TNOTE_t + FR\_DISCRT) / 100. \tag{298}$$

$$COST\_OF\_EQUITY_t = (TNOTE_t \ / 100. \tag{299}$$

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:

$$FR\_TAXES_t = (FR\_TXR + FR\_OTXR) * FR\_NETPFT_t \tag{300}$$

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:

$$FR\_NETPFT_t = (FR\_TRRB_t - FR\_LTD_t) \tag{301}$$

$$FR\_LTD_t = FR\_DEBTRATIO * (TNOTE_t + FR\_DISCRT) / 100.0 * FR\_NPIS_t \tag{302}$$

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:

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[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).

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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

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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).

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Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618(98) (Washington, DC, May 1998).

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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).

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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.

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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*.

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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:

$$\begin{aligned}\text{LN\_CONS\_RES} = {} & (\beta_0*(1 - \beta_{-1}) + (\beta_1*(1 - \beta_{-1})*\text{LN\_RES\_CUST}) \\ & + (\beta_{-1}*(\text{LN\_CONS\_RES}(-1)*1000)))/1000.\end{aligned}$$

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:

$$\mathrm{Ln}(R\_CWC_{a,t}) = CWC\_C_a * (1-\rho) + CWC\_TOM * \mathrm{Ln}(R\_TOM_{a,t}) + \rho * \mathrm{Ln}(R\_CWC_{a,t-1}) - \rho * CWC\_TOM * \mathrm{Ln}(R\_TOM_{a,t-1})$$

Stage 2:

$$R\_CWC_{a,t} = CWC\_K * \exp(\mathrm{Ln}(R\_CWC_{a,t}))$$

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.

$$\begin{aligned} DDA\_E_{a,t} = {} & DDA\_C_a * ARC_a + DDA\_NPIS * NPIS_{a,t-1} + \\ & DDA\_NEWCAP * NEWCAP\_E_{a,t} \end{aligned}$$

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, $deltaADIT_{a,t}$, 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:

$$delta\,ADIT_{a,t} = ADIT\_C_a * ARC_a + \beta_1 * NEWCAP_{a,t} + \beta_2 * NEWCAP_{a,t} + \beta_3 * NEWCAP_{a,t}$$

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	

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value	Symbol
C	.039682	.072242	.549291	[.590]	β_0
LNSUPPLYP87	.231404	.105606	2.19120	[.043]	β_1
LNNGAP87	.726227	.073700	9.85385	[.000]	β_2

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:

$$\ln TRS_{r,n,t} = \sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QRS\_NUMR_{r,n,t} + \beta_{2,n} * \ln NUMRS_{r,t} +$$
$$\rho_n * \ln TRS_{r,n,t-1} - \rho_n * (\sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QRS\_NUMR_{r,n,t-1} + \beta_{2,n} * \ln NUMRS_{r,t}$$

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_SF$_2$]
REG_r	=	1, if observation is in region r, =0 otherwise
$QCM\_FLRr_{r,n,t}$	=	commercial gas consumption per floorspace for region r in year t (Bcf) [(BASQTY_SF$_2$+BASQTY_SI$_2$)/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.

$$\mathrm{MARKUP}_{n,r,t} = \beta_{0,n} + \sum_{r} \beta_{0,n,r} \mathrm{REG}_{r} + \beta_{1,n} \mathrm{QELEC}_{n,r,t} + \rho * \mathrm{MARKUP}_{n,r,t-1}$$
$$- \rho_{n} * (\beta_{0,n} + \sum_{r} \beta_{0,n,r} \mathrm{REG}_{r} + \beta_{1,n} \mathrm{QELEC}_{n,r,t-1})$$

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:

$$\text{lnGWELLS} = \beta_0 + \beta_1 * \text{lnPGAS2000} + \beta_2 * \text{lnREMAIN} + \beta_3 * \text{lnDRILLCOSTPERGASWELL2000LAG} + \beta_4 * \text{PR\_LAG}$$

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
```

Parameter	Estimate	Standard Error	t-statistic	P-value	Symbol
C	-25.3204	6.81740	-3.71409	[.000]	β_0
LNREMAIN	2.13897	.569561	3.75547	[.000]	β_1
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.

$$CTG\_INVCST = CAPREC + FXOC \tag{306}$$

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.

$$CTG\_ISBL = CTG\_INVLOC * BM\_ISBL / 1000 \tag{307}$$

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

$$CTG\_TFCST = (1 - CTG\_OSBLFAC) * CTG\_ISBL \tag{308}$$

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).

$$CTG\_TPI = CTG\_TFCST + CTG\_OTC \tag{309}$$

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):

$$CTG\_OTC = OTCFAC * CTG\_TFCST \tag{310}$$

where,

$$\begin{aligned} OTCFAC = {} & CTG\_PCTENV + CTG\_PCTCNTG + CTG\_PCTLND + \\ & CTG\_PCTSPECL + CTG\_PCTWC \end{aligned} \tag{311}$$

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.

$$\mathrm{WRKCAP} = \mathrm{CTG\_PCTWC} * \mathrm{CTG\_TFCST} \tag{312}$$

Thus,

$$\mathrm{CTG\_FCI} = \mathrm{CTG\_TPI} - \mathrm{WKRCAP} \tag{313}$$

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):

$$\begin{aligned}\mathrm{TPI\_START} = \mathrm{FVI\_CONSTR} * \mathrm{LAND} + \mathrm{FV\_CONSTR} *\\ (\mathrm{CTG\_FCI} - \mathrm{LAND}) + \mathrm{WRKCAP}\end{aligned} \tag{314}$$

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:

$$\mathrm{RCI\_START} = \mathrm{PV\_PRJ} * (\mathrm{LAND} + \mathrm{WKRCAP} + \mathrm{PRJSDECOM}) \tag{315}$$

The present value of RCI is subtracted from the TPI at startup to determine the present value of the project investment (PVI):

$$PVI\_START = TPI\_START - RCI\_START \tag{316}$$

Thus, the annual capital recovery (ACAPRCV) is given by:

$$ACAPRCV = LC\_LIFE * PVI\_START \tag{317}$$

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:

$$ADEPREC = CTG\_TDI / CTG\_PRJLIFE \tag{318}$$
$$ADEPTAXC = ADEPREC * FEDST\_TAX \tag{319}$$
$$ACAPCHRGAT = ACAPRCV - ADEPTAXC \tag{320}$$
$$DCAPCHRGAT = ACAPCHRGAT / 365 \tag{321}$$

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.

$$CTG\_LABOR = LABORLOC * BM\_LABOR \tag{322}$$

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:

$$FXOC\_STAFF = CTG\_LABOR * CTG\_STAFF\_LCFAC \tag{323}$$

$$\begin{aligned} FXOC\_OH = {} & (CTG\_LABOR + FXOC\_STAFF) \\ & * CTG\_OH\_LCFAC \end{aligned} \tag{324}$$

$$FXOC\_LABOR = CTG\_LABOR + FXOC\_STAFF + FXOC\_OH \quad (325)$$

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.

$$KFAC = -LOG((CTG\_BLDX / NCTGBLT) - 1) \qquad (331)$$

$$PHI = -0.3165 + (0.23221 * CTG\_IINDX) + (0.533 * CTG\_PINDX) - (0.027 * CTG\_SINVST) \qquad (332)$$

$$SHRBLD = 1/(1 + EXP(-KFAC - (YR * PHI))) \qquad (333)$$

$$CTGBND = CTG\_BLDX * SHRBLD \qquad (334)$$

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.

$$CTG\_INVADJ = CTG\_INVBAS * (1 - CTG\_DCLCAPCST)^{(YR - CTG\_BASYR)} \qquad (335)$$

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]

$$CTG\_CSTADD = 15 * TANH(0.4 * (MAX(0, (CTGPRODC / 1127308) - 1))) \qquad (336)$$

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.

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Documentation of the Oil and Gas Supply Module (OGSM)

July 2011

Office of Energy Analysis
U.S. Energy Information Administration
U.S. Department of Energy
Washington, DC 20585

Update Information

This edition of the *Documentation of the Oil and Gas Supply Module* reflects changes made to the oil and gas supply module over the past year for the *Annual Energy Outlook 2011*. The major changes include:

- Texas Railroad Commission District 5 is included in the Southwest region instead of the Gulf Coast region.
- Re-estimation of Lower 48 onshore exploration and development costs.
- Updates to crude oil and natural gas resource estimates for emerging shale plays.
- Addition of play-level resource assumptions for tight gas, shale gas, and coalbed methane (Appendix 2.C).
- Updates to the assumptions used for the announced/nonproducing offshore discoveries.
- Revision of the North Slope New Field Wildcat (NFW) exploration wells drilling rate function. The NFW drilling rate is a function of the low-sulfur light projected crude oil prices and was statically estimated based on Alaska Oil and Gas Conservation Commission well counts and success rates.
- Recalibration of the Alaska oil and gas well drilling and completion costs based on the 2007 American Petroleum Institute Joint Association Survey drilling cost data.
- Updates to oil shale plant configuration, cost of capital calculation, and market penetration algorithms.
- Addition of natural gas processing and coal-to-liquids plants as anthropogenic sources of carbon dioxide (CO_2).

Contents

Appendices

Tables

Figures

1. Introduction

The purpose of this report is to define the objectives of the Oil and Gas Supply Module (OGSM), to describe the model's basic approach, and to provide detail on how the model works. This report is intended as a reference document for model analysts, users, and the public. It is prepared in accordance with the U.S. Energy Information Administration's (EIA) legal obligation to provide adequate documentation in support of its statistical and forecast reports (Public Law 93-275, Section 57(b)(2)).

Projected production estimates of U.S. crude oil and natural gas are based on supply functions generated endogenously within the National Energy Modeling System (NEMS) by the OGSM. The OGSM encompasses both conventional and unconventional domestic crude oil and natural gas supply. Crude oil and natural gas projections are further disaggregated by geographic region. The OGSM projects U.S. domestic oil and gas supply for six Lower 48 onshore regions, three offshore regions, and Alaska. The general methodology relies on forecasted profitability to determine exploratory and developmental drilling levels for each region and fuel type. These projected drilling levels translate into reserve additions, as well as a modification of the production capacity for each region.

The OGSM utilizes both exogenous input data and data from other modules within the NEMS. The primary exogenous inputs are resource levels, finding-rate parameters, costs, production profiles, and tax rates - all of which are critical determinants of the expected returns from projected drilling activities. Regional projections of natural gas wellhead prices and production are provided by the Natural Gas Transmission and Distribution Module (NGTDM). Projections of the crude oil wellhead prices at the OGSM regional level come from the Petroleum Market Model (PMM). Important economic factors, namely interest rates and GDP deflators, flow to the OGSM from the Macroeconomic Module. Controlling information (e.g., forecast year) and expectations information (e.g., expected price paths) come from the Integrating Module (i.e. system module).

Outputs from the OGSM go to other oil and gas modules (NGTDM and PMM) and to other modules of the NEMS. To equilibrate supply and demand in the given year, the NGTDM employs short-term supply functions (with the parameters provided by the OGSM) to determine non-associated gas production and natural gas imports. Crude oil production is determined within the OGSM using short-term supply functions. These short-term supply functions reflect potential oil or gas flows to the market for a 1-year period. The gas functions are used by the NGTDM and the oil volumes are used by the PMM for the determination of equilibrium prices and quantities of crude oil and natural gas at the wellhead. The OGSM also provides projections of natural gas production to the PMM to estimate the corresponding level of natural gas liquids production. Other NEMS modules receive projections of selected OGSM variables for various uses. Oil and gas production is passed to the Integrating Module for reporting purposes. Forecasts of oil and gas production are also provided to the Macroeconomic Module to assist in forecasting aggregate measures of output.

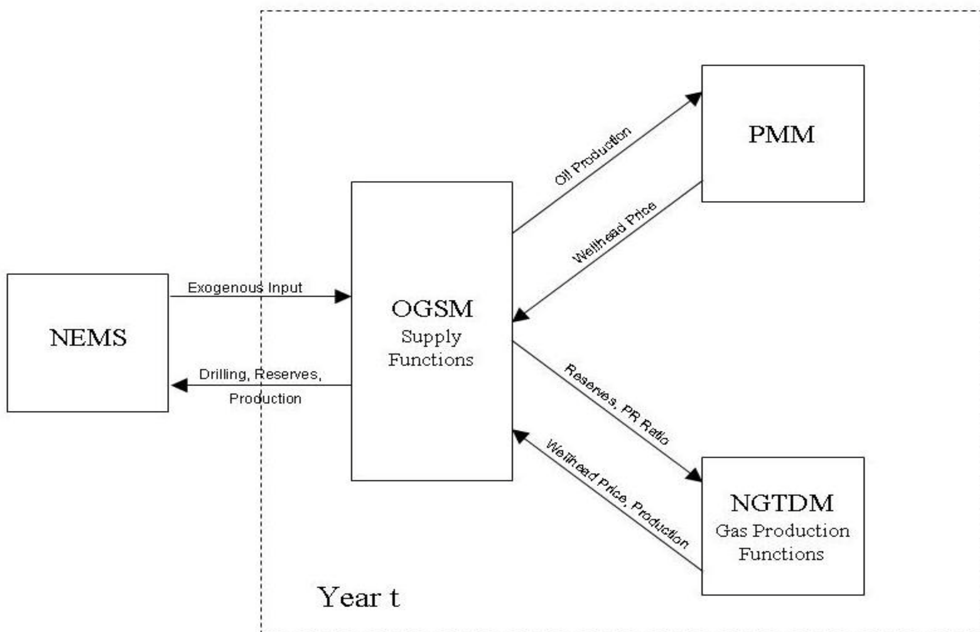
The OGSM is archived as part of the NEMS. The archival package of the NEMS is located under the model acronym NEMS2011. The NEMS version documented is that used to produce the *Annual Energy Outlook 2011 (AEO2011)*. The package is available on the EIA website.[1]

Model Purpose

The OGSM is a comprehensive framework used to analyze oil and gas supply potential and related issues. Its primary function is to produce domestic projections of crude oil and natural gas production as well as natural gas imports and exports in response to price data received endogenously (within the NEMS) from the NGTDM and PMM. Projected natural gas and crude oil wellhead prices are determined within the NGTDM and PMM, respectively. As the supply component only, the OGSM cannot project prices, which are the outcome of the equilibration of both demand and supply.

The basic interaction between the OGSM and the other oil and gas modules is represented in Figure 1-1. The OGSM provides beginning-of-year reserves and the production-to-reserves ratio to the NGTDM for use in its short-term domestic non-associated gas production functions and associated-dissolved natural gas production. The interaction of supply and demand in the NGTDM determines non-associated gas production.

Figure 1-1. OGSM Interface with Other Oil and Gas Modules



[1] ftp://ftp.eia.doe.gov/pub/forecasts/aeo/

The OGSM provides domestic crude oil production to the PMM. The interaction of supply and demand in the PMM determines the level of imports. System control information (e.g., forecast year) and expectations (e.g., expect price paths) come from the Integrating Module. Major exogenous inputs include resource levels, finding-rate parameters, costs, production profiles, and tax rates -- all of which are critical determinants of the oil and gas supply outlook of the OGSM.

The OGSM operates on a regionally disaggregated level, further differentiated by fuel type. The basic geographic regions are Lower 48 onshore, Lower 48 offshore, and Alaska, each of which, in turn, is divided into a number of subregions (see Figure 1-2). The primary fuel types are crude oil and natural gas, which are further disaggregated based on type of deposition, method of extraction, or geologic formation. Crude oil supply includes lease condensate. Natural gas is differentiated by non-associated and associated-dissolved gas.[2] Non-associated natural gas is categorized by fuel type: low-permeability carbonate and sandstone (conventional), high-permeability carbonate and sandstone (tight gas), shale gas, and coalbed methane.

The OGSM provides mid-term (through year 2035) projections and serves as an analytical tool for the assessment of alternative supply policies. One publication that utilizes OGSM forecasts is the *Annual Energy Outlook (AEO)*. Analytical issues that OGSM can address involve policies that affect the profitability of drilling through impacts on certain variables, including:

- drilling and production costs;
- regulatory or legislatively mandated environmental costs;
- key taxation provisions such as severance taxes, State or Federal income taxes, depreciation schedules and tax credits; and
- the rate of penetration for different technologies into the industry by fuel type.

The cash flow approach to the determination of drilling levels enables the OGSM to address some financial issues. In particular, the treatment of financial resources within the OGSM allows for explicit consideration of the financial aspects of upstream capital investment in the petroleum industry.

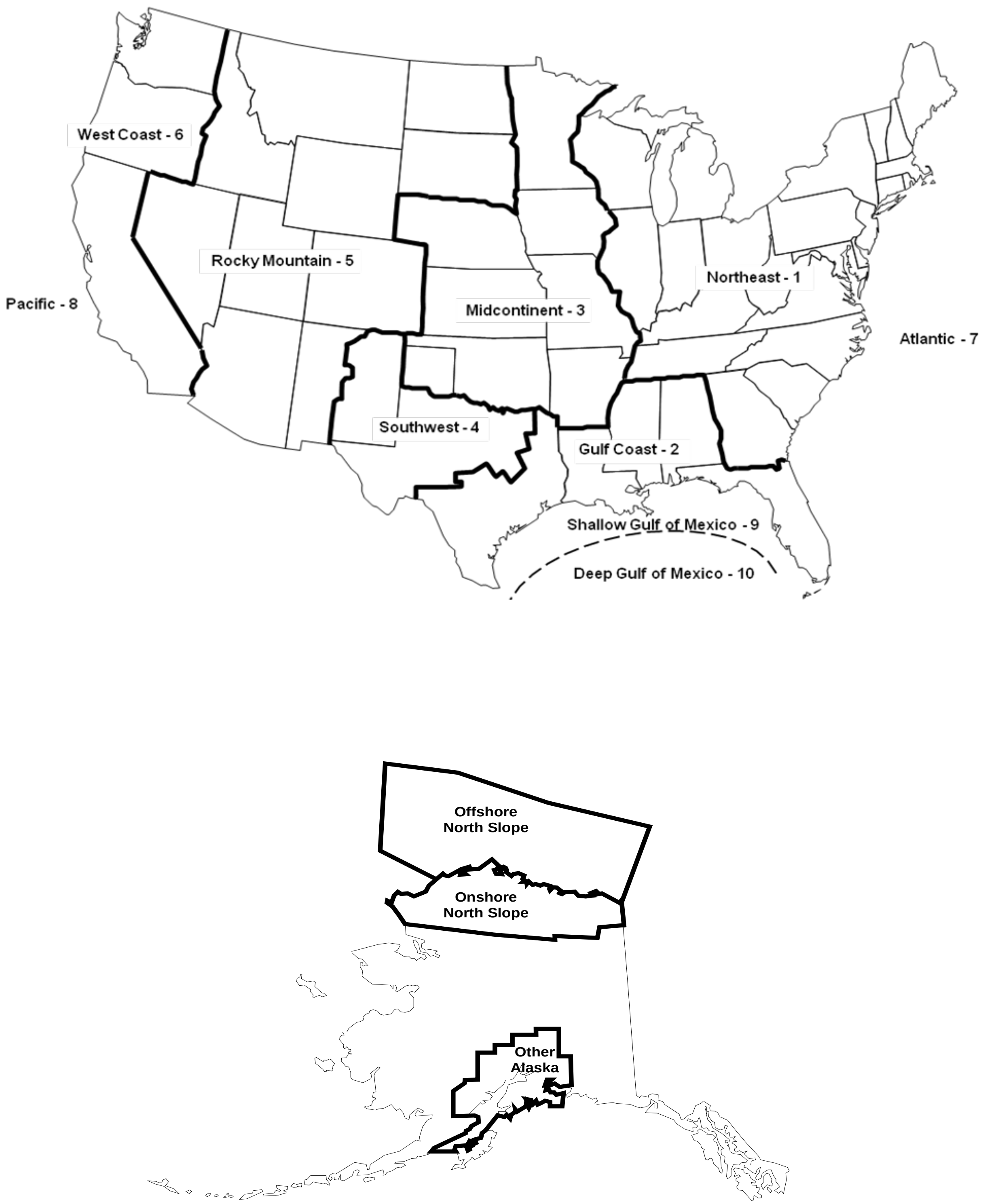
The OGSM is also useful for policy analysis of resource base issues. OGSM analysis is based on explicit estimates for technically recoverable oil and gas resources for each of the sources of domestic production (i.e., geographic region/fuel type combinations). With some modification, this feature could allow the model to be used for the analysis of issues involving:

- the uncertainty surrounding the technically recoverable oil and gas resource estimates, and
- access restrictions on much of the offshore Lower 48 states, the wilderness areas of the onshore Lower 48 states, and the 1002 Study Area of the Arctic National Wildlife Refuge (ANWR).

[2]Nonassociated (NA) natural gas is gas not in contact with significant quantities of crude oil in a reservoir. Associated-dissolved natural gas consists of the combined volume of natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

In general, the OGSM is used to foster a better understanding of the integral role that the oil and gas extraction industry plays with respect to the entire oil and gas industry, the energy subsector of the U.S. economy, and the total U.S. economy.

Figure 1-2. Oil and Gas Supply Regions

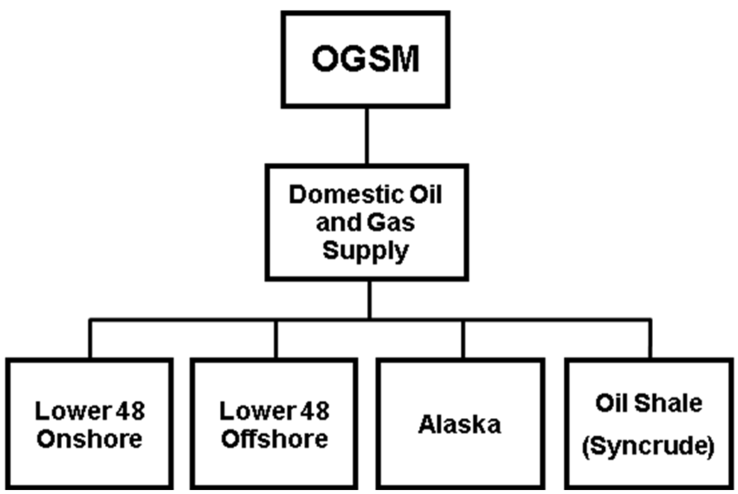


Model Structure

The OGSM consists of a set of submodules (Figure 1-3) and is used to perform supply analysis of domestic oil and gas as part of the NEMS. The OGSM provides crude oil production and parameter estimates representing natural gas supplies by selected fuel types on a regional basis to support the market equilibrium determination conducted within other modules of the NEMS. The oil and gas supplies in each period are balanced against the regionally-derived demand for the produced fuels to solve simultaneously for the market clearing prices and quantities in the wellhead and end-use markets. The description of the market analysis models may be found in the separate methodology documentation reports for the Petroleum Market Module (PMM) and the Natural Gas Transmission and Distribution Model (NGTDM).

The OGSM represents the activities of firms that produce oil and natural gas from domestic fields throughout the United States. The OGSM encompasses domestic crude oil and natural gas supply by both conventional and unconventional recovery techniques. Natural gas is categorized by fuel type: high-permeability carbonate and sandstone (conventional), low-permeability carbonate and sandstone (tight gas), shale gas, and coalbed methane. Unconventional oil includes production of synthetic crude from oil shale (syncrude). Crude oil and natural gas projections are further disaggregated by geographic region. Liquefied natural gas (LNG) imports and pipeline natural gas import/export trade with Canada and Mexico are determined in the NGTDM.

Figure 1-3. Submodules within the Oil and Gas Supply Module



The model's methodology is shaped by the basic principle that the level of investment in a specific activity is determined largely by its expected profitability. Output prices influence oil and gas supplies in distinctly different ways in the OGSM. Quantities supplied as the result of the annual market equilibration in the PMM and the NGTDM are determined as a direct result of the observed market price in that period. Longer-term supply responses are related to investments required for subsequent production of oil and gas. Output prices affect the expected profitability of these investment opportunities as determined by use of a discounted cash flow evaluation of representative prospects. The OGSM incorporates a complete and representative description of the processes by which oil and gas in the technically recoverable resource base[3] convert to proved reserves.[4]

The breadth of supply processes that are encompassed within OGSM result in different methodological approaches for determining crude oil and natural gas production from Lower 48 onshore, Lower 48 offshore, Alaska, and oil shale. The present OGSM consequently comprises four submodules. The Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS) models crude oil and natural gas supply from resources in the Lower 48 States. The Offshore Oil and Gas Supply Submodule (OOGSS) models oil and gas exploration and development in the offshore Gulf of Mexico, Pacific, and Atlantic regions. The Alaska Oil and Gas Supply Submodule (AOGSS) models industry supply activity in Alaska. Oil shale (synthetic) is modeled in the Oil Shale Supply Submodule (OSSS). The distinctions of each submodule are explained in individual chapters covering methodology. Following the methodology chapters, four appendices are included: Appendix A provides a description of the discounted cash flow (DCF) calculation; Appendix B is the bibliography; Appendix C contains a model abstract; and Appendix D is an inventory of key output variables.

[3]*Technically recoverable resources* are those volumes considered to be producible with current recovery technology and efficiency but without reference to economic viability. Technically recoverable volumes include proved reserves and inferred reserves as well as undiscovered and other unproved resources. These resources may be recoverable by techniques considered either conventional or unconventional.

[4]*Proved reserves* are the estimated quantities that analyses of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

2. Onshore Lower 48 Oil and Gas Supply Submodule

Introduction

U.S. onshore lower 48 crude oil and natural gas supply projections are determined by the Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS). The general methodology relies on a detailed economic analysis of potential projects in known crude oil and natural gas fields, enhanced oil recovery projects, developing natural gas plays, and undiscovered crude oil and natural gas resources. The projects that are economically viable are developed subject to the availability of resource development constraints which simulate the existing and expected infrastructure of the oil and gas industries. The economic production from the developed projects is aggregated to the regional and the national levels.

OLOGSS utilizes both exogenous input data and data from other modules within the National Energy Modeling System (NEMS). The primary exogenous data includes technical production for each project considered, cost and development constraint data, tax information, and project development data. Regional projections of natural wellhead prices and production are provided by the Natural Gas Transmission and Distribution Model (NGTDM). From the Petroleum Market Module (PMM) come projections of the crude oil wellhead prices at the OGSM regional level.

Model Purpose

OLOGSS is a comprehensive model with which to analyze the crude oil and natural gas supply potential and related economic issues. Its primary purpose is to project production of crude oil and natural gas from the onshore lower 48 in response to price data received from the PMM and the NGTDM. As a supply submodule, OLOGSS does not project prices.

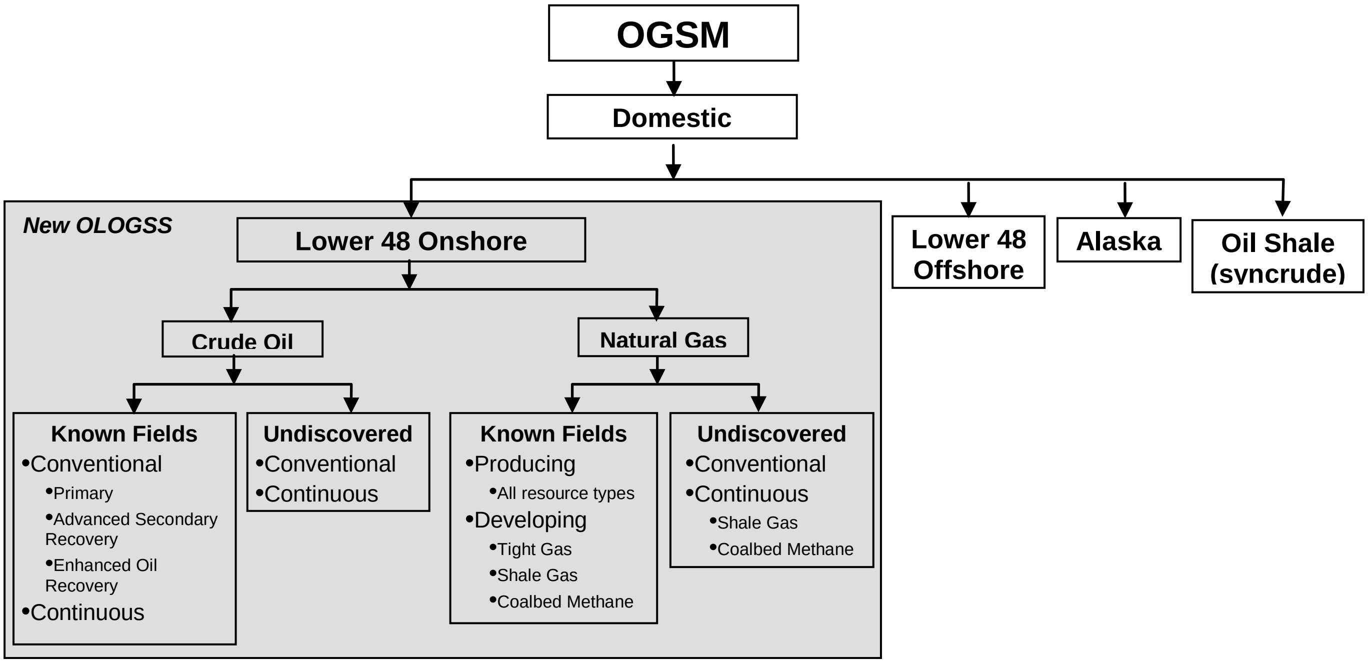
The basic interaction between OLOGSS and the OGSM is illustrated in figure 2-1. As seen in the figure, OLOGSS models the entirety of the domestic crude oil and natural gas production within the onshore lower 48.

Resources Modeled

Crude Oil Resources

Crude oil resources, as illustrated in figure 2-1, are divided into known fields and undiscovered fields. For known resources, exogenous production type curves are used for quantifying the technical production profiles from known fields under primary, secondary, and tertiary recovery processes. Primary resources are also quantified for their advanced secondary recovery (ASR) processes that include the following: waterflooding, infill drilling, horizontal continuity, and horizontal profile modification. Known resources are evaluated for the potential they may possess when employing enhanced oil recovery (EOR) processes such as CO_2 flooding, steam flooding, polymer flooding and profile modification. Known crude oil resources include highly fractured continuous zones such as the Austin chalk formations and the Bakken shale formations.

Figure 2-1: Subcomponents within OGSM



Undiscovered crude oil resources are characterized in a method similar to that used for discovered resources and are evaluated for their potential production from primary and secondary techniques. The potential from an undiscovered resource is defined based on United States Geological Survey (USGS) estimates and is distinguished as either conventional or continuous. Conventional crude oil and natural gas resources are defined as discrete fields with well-defined hydrocarbon-water contacts, where the hydrocarbons are buoyant on a column of water. Conventional resources commonly have relatively high permeability and obvious seals and traps. In contrast, continuous resources commonly are regional in extent, have diffuse boundaries, and are not buoyant on a column of water. Continuous resources have very low permeability, do not have obvious seals and traps, are in close proximity to source rocks, and are abnormally pressured. Included in the category of continuous accumulations are hydrocarbons that occur in tight reservoirs, shale reservoirs, fractured reservoirs, and coal beds.

Natural Gas Resources

Natural gas resources, as illustrated in figure 2-1, are divided into known producing fields, developing natural gas plays, and undiscovered fields. Exogenous production type curves have been used to estimate the technical production from known fields. The undiscovered resources have been characterized based on resource estimates developed by the USGS. Existing databases of developing plays, such as the Marcellus Shale, have been incorporated into the model's resource base. The natural gas resource estimates have been developed from detailed geological characterizations of producing plays.

Processes Modeled

OLOGSS models primary, secondary and tertiary oil recovery processes. For natural gas, OLOGSS models discovered and undiscovered fields, as well as discovered and developing fields. Table 2-1 lists the processes modeled by OLOGSS.

Table 2-1: Processes Modeled by OLOGSS

Crude Oil Processes	Natural Gas Processes
Existing Fields and Reservoirs	Existing Radial Flow
Waterflooding in Undiscovered Resources	Existing Water Drive
CO_2 Flooding	Existing Tight Sands
Steam Flooding	Existing Dry Coal/Shale
Polymer Flooding	Existing Wet Coal/Shale
Infill Drilling	Undiscovered Conventional
Profile Modification	Undiscovered Tight Gas
Horizontal Continuity	Undiscovered Coalbed Methane
Horizontal Profile	Undiscovered Shale Gas
Undiscovered Conventional	Developing Shale Gas
Undiscovered Continuous	Developing Coalbed Methane
	Developing Tight Gas

Major Enhancements

OLOGSS is a play-level model that projects the crude oil and natural gas supply from the onshore lower 48. The modeling procedure includes a comprehensive assessment method for determining the relative economics of various prospects based on future financial considerations, the nature of the undiscovered and discovered resources, prevailing risk factors, and the available technologies. The model evaluates the economics of future exploration and development from the perspective of an operator making an investment decision. Technological advances, including improved drilling and completion practices, as well as advanced production and processing operations are explicitly modeled to determine the direct impacts on supply, reserves, and various economic parameters. The model is able to evaluate the impact of research and development (R&D) on supply and reserves. Furthermore, the model design provides the flexibility to evaluate alternative or new taxes, environmental, or other policy changes in a consistent and comprehensive manner.

OLOGSS provides a variety of levers that allow the user to model developments affecting the profitability of development:

- Development of new technologies
- Rate of market penetration of new technologies
- Costs to implement new technologies
- Impact of new technologies on capital and operating costs
- Regulatory or legislative environmental mandates

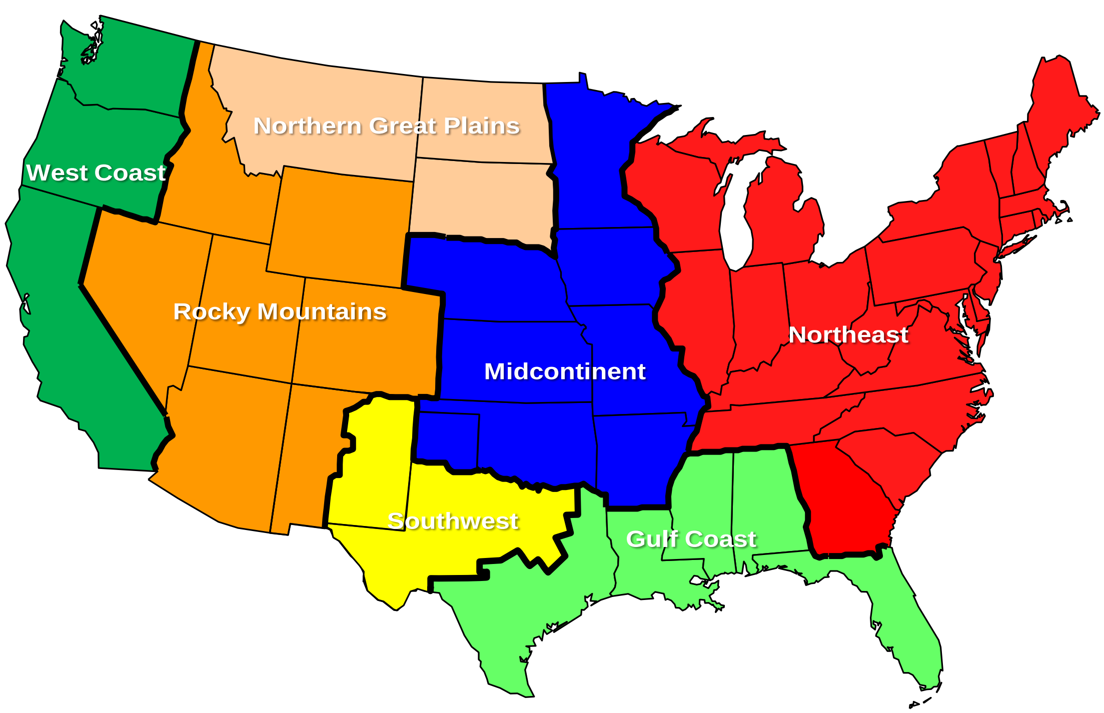
In addition, OLOGSS can quantify the effects of hypothetical developments that affect the resource base. OLOGSS is based on explicit estimates for technically recoverable crude oil and natural gas resources for each source of domestic production (i.e., geographic region/fuel type combinations).

OLOGSS is capable of addressing access issues concerning crude oil and natural gas resources located on federal lands. Undiscovered resources are divided into four categories:

- Officially inaccessible
- Inaccessible due to development constraints
- Accessible with federal lease stipulations
- Accessible under standard lease terms

OLOGSS uses the same geographical regions as the OGSM with one distinction. In order to capture the regional differences in costs and drilling activities in the Rocky Mountain region, the region has been divided into two sub-regions. These regions, along with the original six, are illustrated in figure 2-2. The Rocky Mountain region has been split to add the Northern Great Plains region. The results for these regions are aggregated before being passed to other OGSM or NEMS routines.

Figure 2-2: Seven OLOGSS Regions for Onshore Lower 48



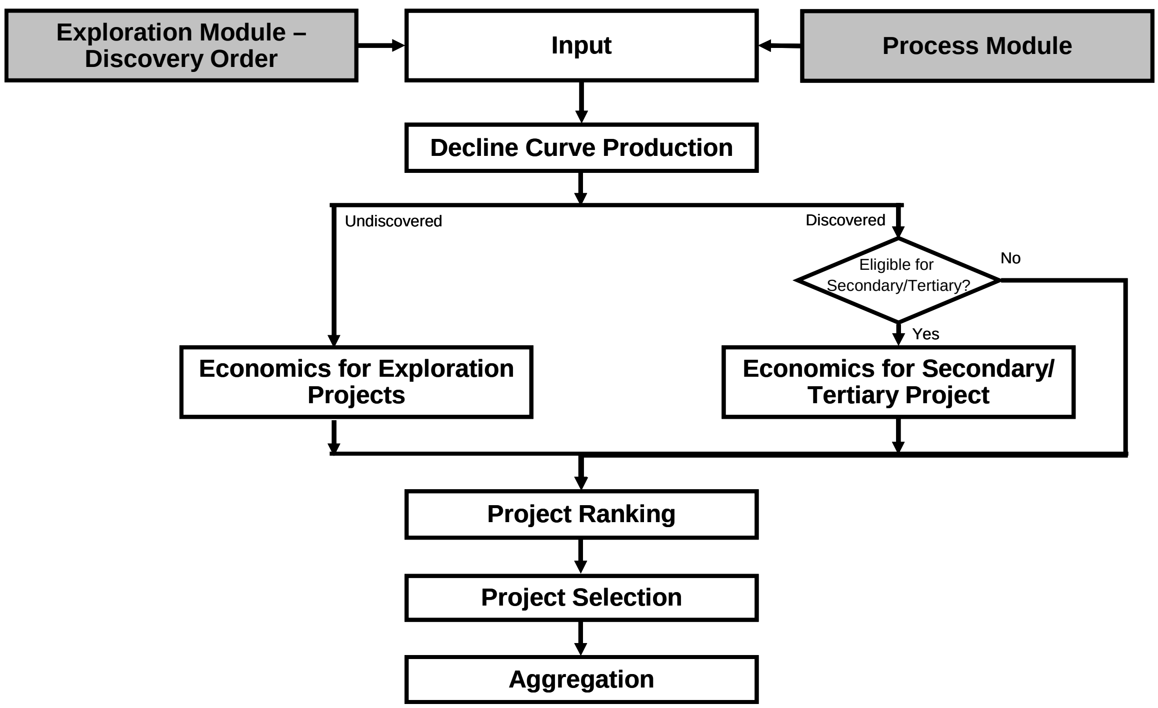
Model Structure

The OLOGSS projects the annual crude oil and natural gas production from existing fields, reserves growth, and exploration. It performs economic evaluation of the projects and ranks the reserves growth and exploration projects for development in a way designed to mimic the way decisions are made by the oil and gas industry. Development decisions and project selection depend upon economic viability and the competition for capital, drilling, and other available development constraints. Finally, the model aggregates production and drilling statistics using geographical and resource categories.

Overall System Logic

Figure 2-3 provides the overall system logic for the OLOGSS timing and economic module. This is the only component of OLOGSS which is integrated into NEMS.

Figure 2-3: OLOGSS Timing Module Overall System Logic



As seen in the figure, there are two primary sources of resource data. The exploration module provides the well-level technical production from the undiscovered projects which may be discovered in the next thirty years. It also determines the discovery order in which the projects will be evaluated by OLOGSS. The process module calculates the well-level technical production from known crude oil and natural gas fields, EOR and advanced secondary recovery (ASR) projects, and developing natural gas plays.

OLOGSS determines the potential domestic production in three phases. As seen in Figure 2-3, the first phase is the evaluation of the known crude oil and natural gas fields using a decline curve analysis. As part of the analysis, each project is subject to a detailed economic analysis used to determine the economic viability and expected life span of the project. In addition, the model applies regional factors used for history matching and resource base coverage. The remaining resources are categorized as either exploration or EOR/ASR. Each year, the exploration projects are subject to economic analysis which determines their economic viability and profitability.

For the EOR/ASR projects, development eligibility is determined before the economic analysis is conducted. The eligibility is based upon the economic life span of the corresponding decline curve project and the process-specific eligibility window. If a project is not currently eligible, it will be re-evaluated in future years. The projects which are eligible are subject to the same type of economic analysis applied to existing and exploration projects in order to determine the viability and relative profitability of the project.

After the economics have been determined for each eligible project, the projects are sorted. The exploration projects maintain their discovery order. The EOR/ASR projects are sorted by their relative profitability. The finalized lists are then considered by the project selection routines.

A project will be selected for development only if it is economically viable and if there are sufficient development resources available to meet the project's requirements. Development resource constraints are used to simulate limits on the availability of infrastructure related to the oil and gas industries. If sufficient resources are not available for an economic project, the project will be reconsidered in future years if it remains economically viable. Other development options are considered in this step, including the waterflooding of undiscovered conventional resources and the extension of CO_2 floods through an increase in total pore volume injected.

The production, reserves, and other key parameters for the timed and developed projects are aggregated at the regional and national levels.

The remainder of this document provides additional details on the logic and particular calculations for each of these steps. These include the decline analysis, economic analysis, timing decisions, project selection, constraints, and modeling of technology.

Known Fields

In this step, the production from existing crude oil and natural gas projects is estimated. A detailed economic analysis is conducted in order to calculate the economically viable production as well as the expected life of each project. The project life is used to determine when a project becomes eligible for EOR and ASR processes.

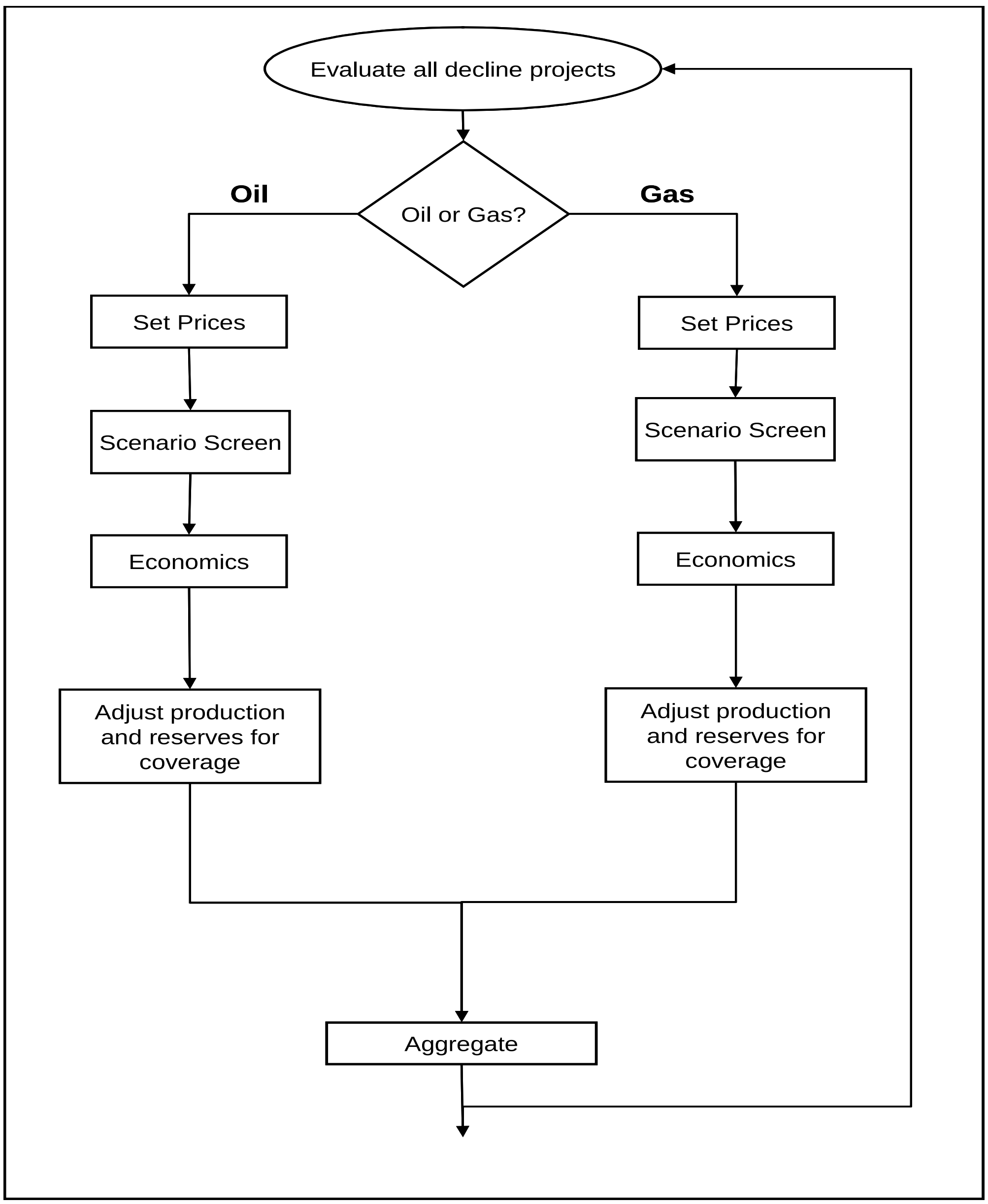
The logic for this process is provided in figure 2-4. For each crude oil project, regional prices are set and the project is screened to determine whether the user has specified any technology and/or economic levers. The screening considers factors including region, process, depth, and several other petro-physical properties. After applicable levers are determined, the project undergoes a detailed economic analysis.

After the analysis, resource coverage factors are applied to the economic production and reserves, and the project results are aggregated at the regional and national levels. In a final step, key parameters including the economic lifespan of the project are stored. A similar process is applied to the existing natural gas fields and reservoirs.

Resource coverage factors are applied in the model to ensure that historical production from existing fields matches that reported by EIA. These factors are calculated at the regional level and applied to production data for the following resources:

- Crude oil (includes lease condensates)
- High-permeability natural gas
- Coalbed methane
- Shale gas
- Tight gas

Figure 2-4: Decline Process Flowchart



Economics

Project Costs

OLOGSS conducts the economic analysis of each project using regional crude oil and natural gas prices. After these prices are set, the model evaluates the base and advanced technology cases for the project. The base case is defined as the current technology and cost scenario for the project; while the advanced case includes technology and/or cost improvements associated with the application of model levers. It is important to note that these cases – for which the assumption are applied to data for the project – are not the same as the *AEO* low, reference, or high technology cases.

For each technology case, the necessary petro-physical properties and other project data are set, the regional dryhole rates are determined, and the process specific depreciation schedule is assigned. The capital and operating costs for the project are then calculated and aggregated for both the base and advanced technology cases.

In the next step, a standard cashflow analysis is conducted, the discounted rate of return is calculated, and the ranking criteria are set for the project. Afterwards, the number and type of wells required for the project, and the last year of actual economic production are set. Finally, the economic variables, including production, development requirements, and other parameters, are stored for project timing and aggregation. All of these steps are illustrated in figure 2-5.

The details of the calculations used in conducting the economic analysis of a project are provided in the following description.

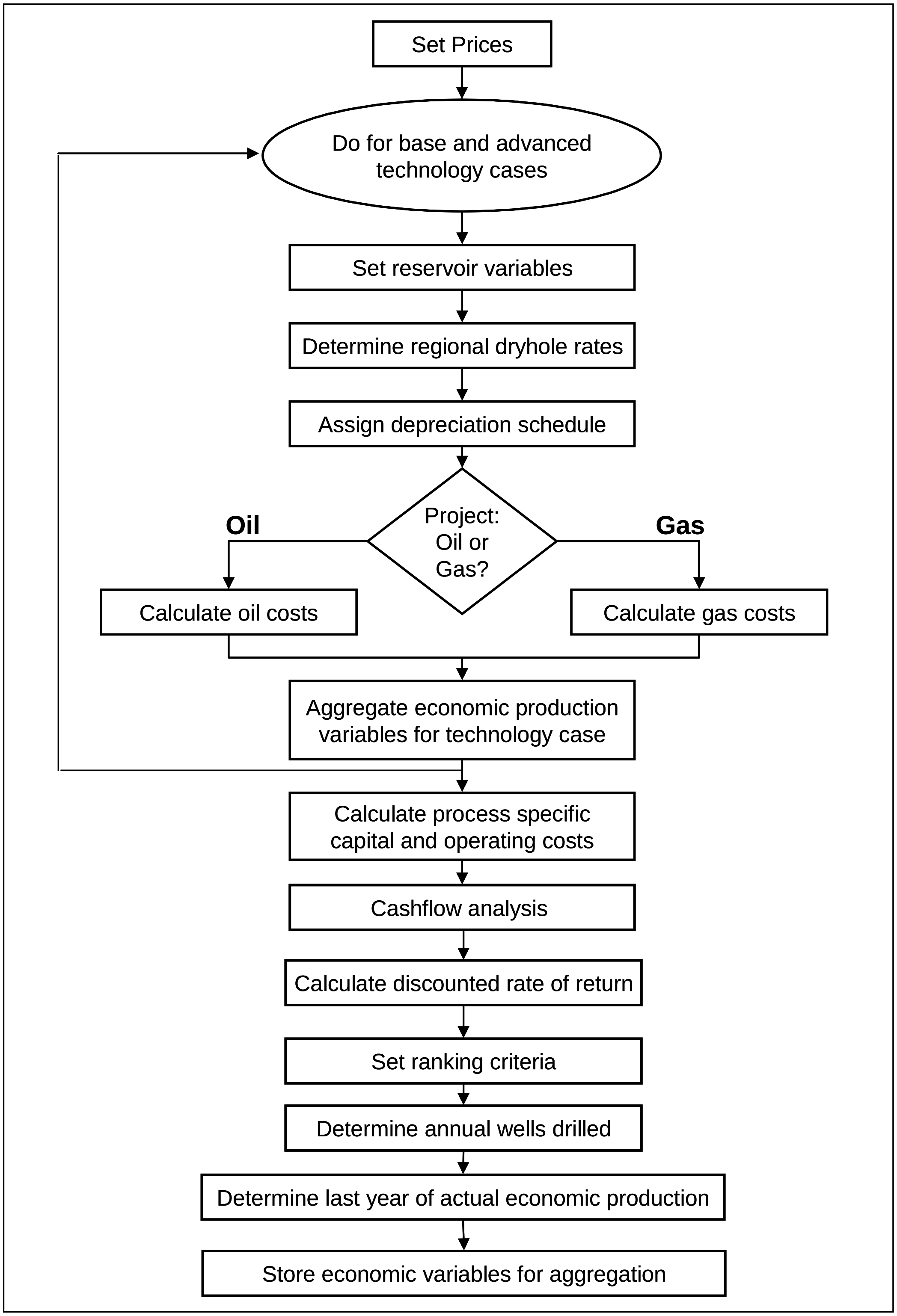
Determine the project shift: The first step is to determine the number of years the project development is shifted, i.e., the numbers of years between the discovery of a project and the start of its development. This will be used to determine the crude oil and natural gas price shift. The number of years is dependent upon both the development schedule – when the project drilling begins – and upon the process.

Determine annual prices: Determine the annual prices used in evaluating the project. Crude oil and natural gas prices in each year use the average price for the previous 5 years.

Begin analysis of base and advanced technology: To capture the impacts of technological improvements on both production and economics, the model divides the project into two categories. The first category – base technology – does not include improvements associated with technology or economic levers. The second category – advanced technology – incorporates the impact of the levers. The division of the project depends on the market penetration algorithm of any applicable technologies.

Determine the dryhole rate for the project: Assigns the regional dryhole rates for undiscovered exploration, undiscovered development, and discovered development. Three types of dryhole rates are used in the model: development in known fields and reservoirs, the first (wildcat) well in an exploration project, and subsequent wells in an exploration project. Specific dryhole rates are used for horizontal drilling and the developing natural gas resources.

Figure 2-5: Economic Analysis Logic



In the advanced case, the dryhole rates may also incorporate technology improvements associated with exploration or drilling success.

$$REGDRYUE_{im} = \left(\frac{SUCEXP_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) * EXPLR\_FAC_{itech} \tag{2-1}$$

$$REGDRYUD_{im} = \left(\frac{SUCEXPD_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-2}$$

$$REGDRYKD_{im} = \left(\frac{SUCDEVE_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-3}$$

If evaluating horizontal continuity or horizontal profile, then,

$$REGDRYKD_{im} = \left(\frac{SUCCHDEV_{im}}{100}\right) * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-4}$$

If evaluating developing natural gas resources, then,

$$REGDRYUD_{im} = ALATNUM_{ires} * \left(1.0 - DRILL\_FAC_{itech}\right) \tag{2-5}$$

where

ITECH	=	Technology case number
IM	=	Region number
REGDRYUE	=	Project specific dryhole rate for undiscovered exploration (Wildcat)
REGDRYUD	=	Project specific dryhole rate for undiscovered development
REGDRYKD	=	Project specific dryhole rate for known field development
SUCEXPD	=	Regional dryhole rate for undiscovered development
ALATNUM	=	Variable representing the regional dryhole rate for known field development
SUCDEVE	=	Regional dryhole rate for undiscovered exploration (Wildcat)
SUCCDEVH	=	Dryhole rate for horizontal drilling
DRILL_FAC	=	Technology lever applied to dryhole rate
EXPLR_FAC	=	Technology factor applied to exploratory dryhole rate

Process specific depreciation schedule: The default depreciation schedule is based on an eight-year declining balance depreciation method. The user may select process-specific depreciation schedules for CO2 flooding, steam flooding, or water flooding in the input file.

Calculate the capital and operating costs for the project: The project costs are calculated for each technology case. The costs are specific to crude oil or natural gas resources. The results of the cost calculations, which include technical crude oil and natural gas production, as well as drilling costs, facilities costs, and operating costs, are then aggregated to the project level.

G & G factor: Calculates the geological and geophysical (G&G) factor for each technology case. This is added to the first year cost.

$$GG_{\mathrm{itech}} = GG_{itech} + DRL\_CST_{itech} * INTANG\_M_{itech} * GG\_FAC \tag{2-6}$$

where

GG_{itech}	=	Geophysical and Geological costs for the first year of the project
DRL_CST_{itech}	=	Total drilling cost for the first year of the project
$INTANG\_M_{itech}$	=	Energy Elasticity factor for intangible investments (first year)
GG_FAC	=	Portion of exploratory costs that is G&G costs

After the variables are aggregated, the technology case loop ends. At this point, the process specific capital costs, which apply to the entire project instead of the technology case, are calculated.

Cashflow Analysis: The model then conducts a cashflow analysis on the project and calculates the discounted rate of return. Economic Analysis is conducted using a standard cashflow routine described in Appendix A.

Calculate the discounted rate of return: Determines the projected rate of return for all investments and production. The cumulative investments and discounted after tax cashflow are used to calculate the investment efficiency for the project.

Calculate wells: The annual number of new and existing wells is calculated for the project. The model tracks five drilling categories:

- New production wells drilled
- New injection wells drilled
- Active production wells
- Active injection wells
- Shut in wells

The calculation of the annual well count depends on the number of existing production and injection wells as well as on the process and project-specific requirements to complete each drilling pattern developed.

Determine number of years a project is economic: The model calculates the last year of actual economic production. This is based on both the results of the cashflow analysis and the annual production in year specified by the analysis. The last year of production is used to determine the aggregation range to be used if the project is selected for development.

If the project is economic only in the first year, it will be considered uneconomic and unavailable for development at that time. If this occurs for an existing crude oil or natural gas project, the model will assume that all of the wells will be shut in.

Non-producing decline project: Determines if the existing crude oil or natural gas project is non-producing. If there is no production, then the end point for project aggregation is not calculated. This check applies only to the existing crude oil and natural gas projects

Ranking criteria: Ranks investment efficiency based on the discounted after tax cashflow over tangible and intangible investments.

Determine ranking criterion: The ranking criterion, specified by the user, is the parameter by which the projects will be sorted before development. Ranking criteria options include the project net present value, the rate of return for the project, and the investment efficiency.

Calculating Unit Costs

To conduct the cost analysis, the model calculates price adjustment factors as well as unit costs for all required capital and operating costs. Unit costs include the cost of drilling and completing a single well, producing one barrel of crude oil, or operating one well for a year. These costs are adjusted using the technology levers and CPI indices. After the development schedule for the project is determined and the economic life of a single well is calculated, the technical production and injection are determined for the project. Based on the project's development schedule and the technical production, the annual capital and operating costs are determined. In the final step, the process and resource specific capital and operating costs are calculated for the project. These steps are illustrated in figure 2-6.

The Onshore Lower 48 Oil and Gas Supply Submodule uses detailed project costs for economic calculations. There are three broad categories of costs used by the model: capital costs, operating costs, and other costs. These costs are illustrated in figure 2-7. Capital costs encompass the costs of drilling and equipment necessary for the production of crude oil and natural gas resources. Operating costs are used to calculate the full life cycle economics of the project. Operating costs consist of normal daily expenses and surface maintenance. Other cost parameters include royalty, state and federal taxes, and other required schedules and factors.

The calculations for capital costs and operating costs for both crude oil and natural gas are described in detail below. The capital and operating costs are used in the timing and economic module to calculate the lifecycle economics for all crude oil and natural gas projects.

There are two categories for these costs: costs that are applied to all processes, thus defined as *resource independent*, and the process-specific costs, or *resource dependent* costs. Resource dependent costs are used to calculate the economics for existing, reserves growth, and exploration projects. The capital costs for both crude oil and natural gas are calculated first, followed by the resource independent costs, and then the resource dependent costs.

The resource independent and resource dependent costs applied to each of the crude oil and natural gas processes are detailed in tables 2-2 and 2-3 respectively.

Figure 2-6: Project Cost Calculation Procedure

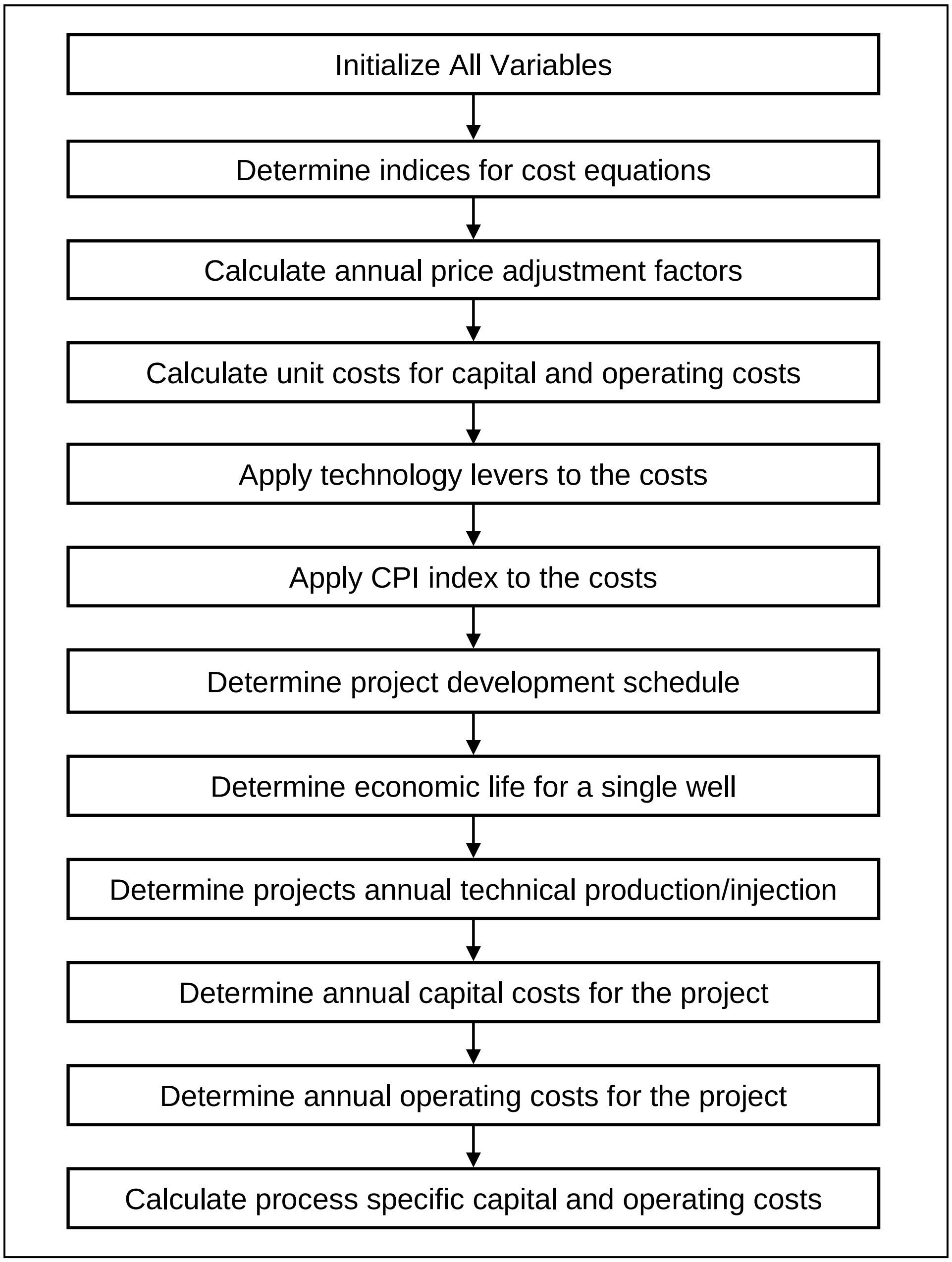


Figure 2-7: Cost Data Types and Requirements

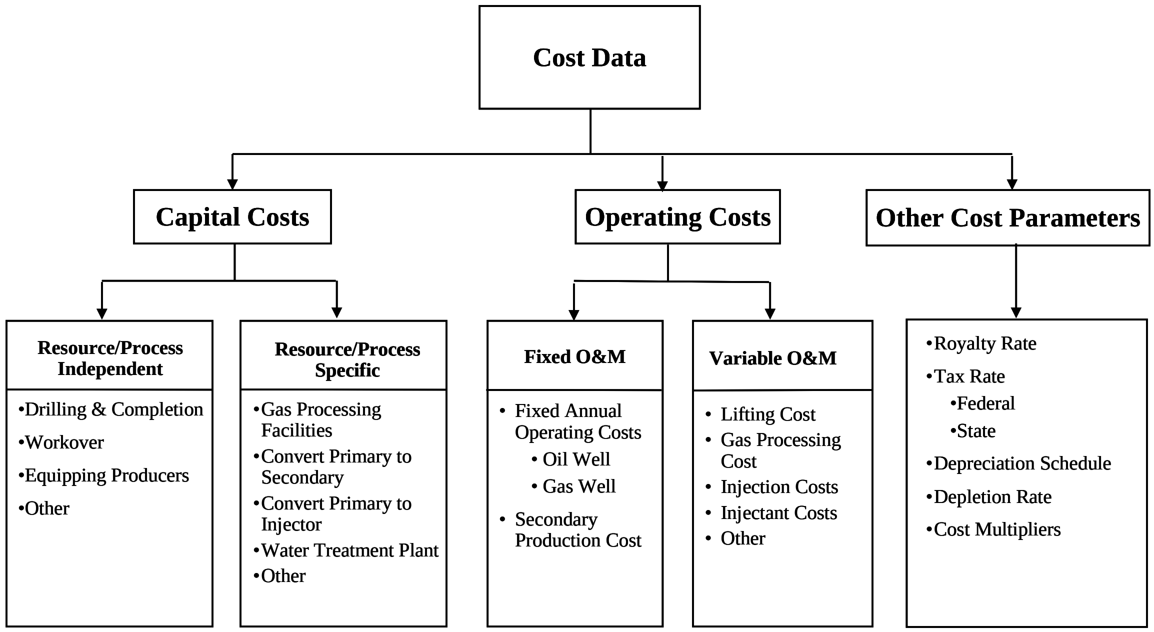


Table 2-2: Costs Applied to Crude Oil Processes

	Capital Cost for Oil	Existing	Water Flooding	CO2 Flooding	Steam Flooding	Polymer Flooding	Infill Drilling	Profile Modification	Undiscovered
Resource Independent	Vertical Drilling Cost	v	v	v	v	V	v	v	v
	Horizontal Drilling Cost								
	Drilling Cost for Dryhole	v	v	v	v	V	v	v	v
	Cost to Equip a Primary Producer		v	v	v	V	v	v	v
	Workover Cost		v	v	v	V	v	v	v
	Facillities Upgrade Cost		v	v	v	V	v	v	
	Fixed Annual Cost for Oil Wells	v	v	v	v	V	v	v	v
	Fixed Annual Cost for Secondary Production		v	v	v	V	v	v	v
	Lifting Cost		v	v	v	V	v	v	v
	O & M Cost for Active Patterns		v			V		v	
	Variable O & M Costs	v	v	v	v	V	v	v	v
	Socondary Workover Cost		v	v	v	V	v	v	v
Resource Dependent	Cost of Water Handling Plant		v			V		v	
	Cost of Chemical Plant					V			
	CO2 Recycle Plant			v					
	Cost of Injectant					V			
	Cost to Convert a Primary to Secondary Well		v	v	v	V	v	v	v
	Cost to Convert a Producer to an Injector		v	v	v	V	v	v	v
	Fixed O & M Cost for Secondary Operations		v	v	v	V	v	v	v
	Cost of a Water Injection Plant		v						
	O & M Cost for Active Patterns per Year		v			V		v	
	Cost to Inject CO2			v					
	King Factor				v				
	Steam Manifolds Cost				v				
	Steam Generators Cost				v				
	Cost to Inject Poloymer					V		v	

Table 2-3: Costs Applied to Natural Gas Processes

	Capital Costs for Gas	Conventional Radial Gas	Water Drive	Tight Sands	Coal/Shale Gas	Undiscovered Conventional
Resource Independent	Vertical Drilling Cost	v	v	v	v	v
	Horizontal Drilling Cost	v	v	v	v	v
	Drilling Cost for Dryhole	v	v	v	v	v
	Gas Facilities Cost	v	v	v	v	v
	Fixed Annual Costs for Gas Wells	v	v	v	v	v
	Gas Stimulation Costs	v	v	v	v	v
	Overhead Costs	v	v	v	v	v
	Variable O & M Cost	v	v	v	v	v
Resource Dependent	Gas Processing and Treatment Facilities	v	v	v	v	v

The following section details the calculations used to calculate the capital and operating costs for each crude oil and natural gas project. The specific coefficients are econometrically estimated according to the corresponding equations in Appendix 2.B.

Cost Multipliers

Cost multipliers are used to capture the impact on capital and operating costs associated with changes in energy prices. OLOGSS calculates cost multipliers for tangible and intangible investments, operating costs, and injectants (polymer and CO_2). The methodology used to calculate the multipliers is based on the National Energy Technology Laboratory (NETL's) Comprehensive Oil and Gas Analysis Model as well as the 1984 Enhanced Oil Recovery Study completed by the National Petroleum Council.

The multipliers for operating costs and injectant are applied while calculating project costs. The investment multipliers are applied during the cashflow analysis. The injectant multipliers are held constant for the analysis period while the others vary with changing crude oil and natural gas prices.

Operating Costs for Crude Oil: Operating costs are adjusted by the change between current crude oil prices and the base crude oil price. If the crude oil price in a given year falls below a pre-established minimum price, the adjustment factor is calculated using the minimum crude oil price.

$$\mathrm{TERM} = \left(\frac{\mathrm{OILPRICE}_{iyr} - \mathrm{BASEOIL}}{\mathrm{BASEOIL}}\right) \tag{2-7}$$

$$\mathrm{INTANG\_M}_{iyr} = 1.0 + (\mathrm{OMULT\_INT} * \mathrm{TERM}) \tag{2-8}$$

$$\mathrm{TANG\_M}_{iyr} = 1.0 + (\mathrm{OMULT\_TANG} * \mathrm{TERM}) \tag{2-9}$$

$$\mathrm{OAM\_M}_{iyr} = 1.0 + (\mathrm{OMULT\_OAM} * \mathrm{TERM}) \tag{2-10}$$

where

IYR	=	Year
TERM	=	Fractional change in crude oil prices (from base price)
BASEOIL	=	Base crude oil price used for normalization of capital and operating costs
OMULT_INT	=	Coefficient for intangible crude oil investment factor
OMULT_TANG	=	Coefficient for tangible crude oil investment factor
OMULT_OAM	=	Coefficient for O & M factor
INTANG_M	=	Annual energy elasticity factor for intangible investments
TANG_M	=	Annual energy elasticity factor for tangible investments
OAM_M	=	Annual energy elasticity factor for crude oil O & M

Cost Multipliers for Natural Gas:

$$TERM = \left(\frac{GASPRICEC_{iyr} - BASEGAS}{BASEGAS}\right) \quad (2\text{-}11)$$

$$TANG\_M_{iyr} = 1.0 + (GMULT\_TANG * TERM) \quad (2\text{-}12)$$

$$INTANG\_M_{iyr} = 1.0 + (GMULT\_INT * TERM) \quad (2\text{-}13)$$

$$OAM\_M_{iyr} = 1.0 + (GMULT\_OAM * TERM) \quad (2\text{-}14)$$

where

GASPRICEC	=	Annual natural gas price
IYR	=	Year
TERM	=	Fractional change in natural gas prices
BASEGAS	=	Base natural gas price used for normalization of capital and operating costs
GMULT_INT	=	Coefficient for intangible natural gas investment factor
GMULT_TANG	=	Coefficient for tangible natural gas investment factor
GMULT_OAM	=	Coefficient for O & M factor
INTANG_M	=	Annual energy elasticity factor for intangible investments
TANG_M	=	Annual energy elasticity factor for tangible investments
OAM_M	=	Annual energy elasticity factor for crude oil O & M

Cost Multipliers for Injectant:

In the first year of the project:

$$FPLY = 1.0 + (0.3913 * TERM) \quad (2\text{-}15)$$

$$FCO2 = \frac{0.5 + 0.013 * BASEOIL * (1.0 + TERM)}{0.5 + 0.013 * BASEOIL} \quad (2\text{-}16)$$

where

TERM	=	Fractional change in crude oil prices
BASEOIL	=	Base crude oil price used for normalization of capital and operating costs
FPLY	=	Energy elasticity factor for polymer

FCO2 = Energy elasticity factor for natural CO_2 prices

Resource Independent Capital Costs for Crude Oil

Resource independent capital costs are applied to both crude oil and natural gas projects, regardless of the recovery method applied. The major resource independent capital costs are as follows: drilling and completion costs, the cost to equip a new or primary producer, and workover costs.

Drilling and Completion Costs: Drilling and completion costs incorporate the costs to drill and complete a crude oil or natural gas well (including tubing costs), and logging costs. These costs do not include the cost of drilling a dryhole/wildcat during exploration. OLOGSS uses a separate cost estimator, documented below, for dryholes drilled. Vertical well drilling costs include drilling and completion of vertical, tubing, and logging costs. Horizontal well costs include costs for drilling and completing a vertical well and the horizontal laterals.

Horizontal Drilling for Crude Oil:

$$DWC\_W = OIL\_DWCK_{r,d} + (OIL\_DWCA_{r,d} * DEPTH^2) + (OIL\_DWCB_{r,d} * DEPTH^2 * NLAT) + (OIL\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}17)$$

Vertical Drilling for Crude Oil:

$$DWC\_W = OIL\_DWCK_{r,d} + (OIL\_DWCA_{r,d} * DEPTH) + (OIL\_DWCB_{r,d} * DEPTH^2) + (OIL\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}18)$$

where

DWC_W	=	Cost to drill and complete a crude oil well (K$/Well)
r	=	Region number
d	=	Depth category number
OIL_DWCA, B, C, K	=	Coefficients for crude oil well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral

Horizontal Drilling for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH^2) + (DRY\_DWCB_{r,d} * DEPTH^2 * NLAT) + (DRY\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}19)$$

Vertical Drilling for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH) + (DRY\_DWCB_{r,d} * DEPTH^2) + (DRY\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}20)$$

where

DRY_W	=	Cost to drill a dry well (K$/Well)
R	=	Region number
D	=	Depth category number
DRY_DWCA, B, C, K	=	Coefficients for dry well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral

Cost to Equip a New Producer: The cost of equipping a primary producing well includes the production equipment costs for primary recovery.

$$NPR\_W = NPRK_{r,\,d} + (NPRA_{r,\,d} * DEPTH) + (NPRB_{r,\,d} * DEPTH^2) + (NPRC_{r,\,d} * DEPTH^3) \quad (2\text{-}21)$$

where

NPR_W	=	Cost to equip a new producer (K$/Well)
R	=	Region number
D	=	Depth category number
NPRA, B, C, K	=	Coefficients for new producer equipment cost equation
DEPTH	=	Well depth

Workover Costs: Workover, also known as stimulation is done every 2-3 years to increase the productivity of a producing well. In some cases workover or stimulation of a wellbore is required to maintain production rates.

$$WRK\_W = WRKK_{r,\,d} + (WRKA_{r,\,d} * DEPTH) + (WRKB_{r,\,d} * DEPTH^2) + (WRKC_{r,\,d} * DEPTH^3) \quad (2\text{-}22)$$

Where,

WRK_W	=	Cost for a well workover (K$/Well)
R	=	Region number
D	=	Depth category number
WRKA, B, C, K	=	Coefficients for workover cost equation
DEPTH	=	Well depth

Facilities Upgrade Cost: Additional cost of equipment upgrades incurred when converting a primary producing well to a secondary resource recovery producing well. Facilities upgrade costs consist of plant costs and electricity costs.

$$FAC\_W = FACUPK_{r,\,d} + (FACUPA_{r,\,d} * DEPTH) + (FACUPB_{r,\,d} * DEPTH^2) + (FACUPC_{r,\,d} * DEPTH^3) \quad (2\text{-}23)$$

where

FAC_W	=	Well facilities upgrade cost (K$/Well)
R	=	Region number
D	=	Depth category number
FACUPA, B, C, K	=	Coefficients for well facilities upgrade cost equation

DEPTH = Well depth

Resource Independent Capital Costs for Natural Gas

Drilling and Completion Costs: Drilling and completion costs incorporate the costs to drill and complete a crude oil or natural gas well (including tubing costs), and logging costs. These costs do not include the cost of drilling a dryhole/wildcat during exploration. OLOGSS uses a separate cost estimator, documented below, for dryholes drilled. Vertical well drilling costs include drilling and completion of vertical, tubing, and logging costs. Horizontal well costs include costs for drilling and completing a vertical well and the horizontal laterals.

Vertical Drilling Costs:

$$DWC\_W = GAS\_DWCK_{r,d} + (GAS\_DWCA_{r,d} * DEPTH) + (GAS\_DWCB_{r,d} * DEPTH^2) + (GAS\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}24)$$

Horizontal Drilling Costs:

$$DWC\_W = GAS\_DWCK_{r,d} + (GAS\_DWCA_{r,d} * DEPTH^2) + (GAS\_DWCB_{r,d} * DEPTH^2 * NLAT) + (GAS\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}25)$$

Where,

DWC_W	=	Cost to drill and complete a natural gas well (K$/Well)
R	=	Region number
D	=	Depth category number
GAS_DWCA, B, C, K	=	Coefficients for natural gas well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral

Vertical Drilling Costs for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH) + (DRY\_DWCB_{r,d} * DEPTH^2) + (DRY\_DWCC_{r,d} * DEPTH^3) \quad (2\text{-}26)$$

Horizontal Drilling Costs for a Dry Well:

$$DRY\_W = DRY\_DWCK_{r,d} + (DRY\_DWCA_{r,d} * DEPTH^2) + (DRY\_DWCB_{r,d} * DEPTH^2 * NLAT) + (DRY\_DWCC_{r,d} * DEPTH^2 * NLAT * LATLEN) \quad (2\text{-}27)$$

where

DRY_W	=	Cost to drill a dry well (K$/Well)
R	=	Region number
D	=	Depth category number
DRY_DWCA, B, C, K	=	Coefficients for dry well drilling cost equation
DEPTH	=	Well depth
NLAT	=	Number of laterals
LATLEN	=	Length of lateral

Facilities Cost: Additional cost of equipment upgrades incurred when converting a primary producing well to a secondary resource recovery producing well. Facilities costs consist of flowlines and connections, production package costs, and storage tank costs.

$$FWC\_W_{iyr} = FACGK_{r,d} + (FACGA_{r,d} * DEPTH) + (FACGB_{r,d} * PEAKDAILY\_RATE) + (FACGC_{r,d} * DEPTH * PEAKDAILY\_RATE) \quad (2\text{-}28)$$

where

FWC_W	=	Facilities cost for a natural gas well (K$/Well)
R	=	Region number
D	=	Depth category number
FACGA, B, C, K	=	Coefficients for facilities cost equation
DEPTH	=	Well depth
PEAKDAILY_RATE	=	Maximum daily natural gas production rate

Fixed Annual Operating Costs: The fixed annual operating costs are applied to natural gas projects in decline curve analysis.

$$FOAMG\_W = OMGK_{r,d} + (OMGA_{r,d} * DEPTH) + (OMGB_{r,d} * PEAKDAILY\_RATE) + (OMGC_{r,d} * DEPTH * PEAKDAILY\_RATE) \quad (2\text{-}29)$$

where

FOAMG_W	=	Fixed annual operating costs for natural gas (K$/Well)
R	=	Region number
D	=	Depth category number
OMGA, B, C, K	=	Coefficients for fixed annual O & M cost equation for natural gas
DEPTH	=	Well depth
PEAKDAILY_RATE	=	Maximum daily natural gas production rate

Resource Independent Annual Operating Costs for Crude Oil

Fixed Operating Costs: The fixed annual operating costs are applied to crude oil projects in decline curve analysis.

$$OMO\_W = OMOK_{r,d} + (OMOA_{r,d} * DEPTH) + (OMOB_{r,d} * DEPTH^2) + (OMOC_{r,d} * DEPTH^3) \quad (2\text{-}30)$$

where

OMO_W	=	Fixed annual operating costs for crude oil wells (K$/Well)
R	=	Region number
D	=	Depth category number
OMOA, B, C, K	=	Coefficients for fixed annual operating cost equation for crude oil
DEPTH	=	Well depth

Annual Costs for Secondary Producers: The direct annual operating expenses include costs in the following major areas: normal daily expenses, surface maintenance, and subsurface maintenance.

$$OPSEC\_W = OPSECK_{r,d} + (OPSECA_{r,d} * DEPTH) + (OPSECB_{r,d} * DEPTH^2) + (OPSECC_{r,d} * DEPTH^3) \quad (2\text{-}31)$$

where

OPSEC_W	=	Fixed annual operating cost for secondary oil operations (K$/Well)
R	=	Region number
D	=	Depth category number
OPSECA, B, C, K	=	Coefficients for fixed annual operating cost for secondary oil operations
DEPTH	=	Well depth

Lifting Costs: Incremental costs are added to a primary and secondary flowing well. These costs include pump operating costs, remedial services, workover rig services and associated labor.

$$OML\_W = OMLK_{r,d} + (OMLA_{r,d} * DEPTH) + (OMLB_{r,d} * DEPTH^2) + (OMLC_{r,d} * DEPTH^3) \quad (2\text{-}32)$$

where

OML_W	=	Variable annual operating cost for lifting (K$/Well)
R	=	Region number
D	=	Depth category number
OMLA, B, C, K	=	Coefficients for variable annual operating cost for lifting equation
DEPTH	=	Well depth

Secondary Workover: Secondary workover, also known as stimulation is done every 2-3 years to increase the productivity of a secondary producing well. In some cases secondary workover or stimulation of a wellbore is required to maintain production rates.

$$SWK\_W = OMSWRK_{r,d} + (OMSWR\ A_{r,d} * DEPTH) + (OMSWR\ B_{r,d} * DEPTH^2) + (OMSWR\ C_{r,d} * DEPTH^3) \quad (2\text{-}33)$$

where

SWK_W	=	Secondary workover costs (K$/Well)
R	=	Region number
D	=	Depth category number
OMSWRA, B, C, K	=	Coefficients for secondary workover costs equation
DEPTH	=	Well depth

Stimulation Costs: Workover, also known as stimulation is done every 2-3 years to increase the productivity of a producing well. In some cases workover or stimulation of a wellbore is required to maintain production rates.

$$STIM\_W = \left(\frac{STIM\_A + STIM\_B * DEPTH}{1000}\right) \tag{2-34}$$

where

STIM_W	=	Oil stimulation costs (K$/Well)
STIM_A, B	=	Stimulation cost equation coefficients
DEPTH	=	Well depth

Resource Dependent Capital Costs for Crude Oil

Cost to Convert a Primary Well to a Secondary Well: These costs consist of additional costs to equip a primary producing well for secondary recovery. The cost of replacing the old producing well equipment includes costs for drilling and equipping water supply wells but excludes tubing costs.

$$PSW\_W = PSWK_{r,d} + (PSWA_{r,d} * DEPTH) + (PSWB_{r,d} * DEPTH^2) + (PSWC_{r,d} * DEPTH^3) \tag{2-35}$$

where

PSW_W	=	Cost to convert a primary well into a secondary well (K$/Well)
R	=	Region number
D	=	Depth category number
PSWA, B, C, K	=	Coefficients for primary to secondary well conversion cost equation
DEPTH	=	Well depth

Cost to Convert a Producer to an Injector: Producing wells may be converted to injection service because of pattern selection and favorable cost comparison against drilling a new well. The conversion procedure consists of removing surface and sub-surface equipment (including tubing), acidizing and cleaning out the wellbore, and installing new 2- 7/8 inch plastic-coated tubing and a waterflood packer (plastic-coated internally and externally).

$$PSI\_W = PSIK_{r,d} + (PSIA_{r,d} * DEPTH) + (PSIB_{r,d} * DEPTH^2) + (PSIC_{r,d} * DEPTH^3) \tag{2-36}$$

where

PSI_W	=	Cost to convert a producing well into an injecting well (K$/Well)
R	=	Region number
D	=	Depth category number
PSIA, B, C, K	=	Coefficients for producing to injecting well conversion cost equation
DEPTH	=	Well depth

Cost of Produced Water Handling Plant: The capacity of the water treatment plant is a function of the maximum daily rate of water injected and produced (MBbl) throughout the life of the project.

$$PWP\_F = PWHP * \left(\frac{RMAXW}{365}\right) \tag{2-37}$$

where

PWP_F	=	Cost of the produced water handling plant (K$/Well)
PWHP	=	Produced water handling plant multiplier
RMAXW	=	Maximum pattern level annual water injection rate

Cost of Chemical Handling Plant (Non-Polymer): The capacity of the chemical handling plant is a function of the maximum daily rate of chemicals injected throughout the life of the project.

$$CHM\_F = CHMK * CHMA * \left(\frac{RMAXP}{365}\right)^{CHMB} \tag{2-38}$$

where

CHM_F	=	Cost of chemical handling plant (K$/Well)
CHMB	=	Coefficient for chemical handling plant cost equation
CHMK, A	=	Coefficients for chemical handling plant cost equation
RMAXP	=	Maximum pattern level annual polymer injection rate

Cost of Polymer Handling Plant: The capacity of the polymer handling plant is a function of the maximum daily rate of polymer injected throughout the life of the project.

$$PLY\_F = PLYPK * PLYPA * \left(\frac{RMAXP}{365}\right)^{0.6} \tag{2-39}$$

where

PLY_F	=	Cost of polymer handling plant (K$/Well)
PLYPK, A	=	Coefficients for polymer handling plant cost equation
RMAXP	=	Maximum pattern level annual polymer injection rate

Cost of CO_2 Recycling Plant: The capacity of a recycling/injection plant is a function of the maximum daily injection rate of CO_2 (Mcf) throughout the project life. If the maximum CO_2 rate equals or exceeds 60 MBbl/Day then the costs are divided into two separate plant costs.

$$CO2\_F = CO2rk * \left(\frac{0.75 * RMAXP}{365}\right)^{CO2RB} \tag{2-40}$$

where,

CO2_F	=	Cost of CO_2 recycling plant (K$/Well)
CO2RK, CO2RB	=	Coefficients for CO_2 recycling plant cost equation
RMAXP	=	Maximum pattern level annual CO_2 injection rate

Cost of Steam Manifolds and Pipelines: Cost to install and maintain steam manifolds and pipelines for steam flood enhanced oil recovery project.

$$STMM\_F = TOTPAT * PATSZE * STMMA \tag{2-41}$$

where

STMM_F	=	Cost for steam manifolds and generation (K$)
TOTPAT	=	Total number of patterns in the project
PATSZE	=	Pattern size (Acres)
STMMA	=	Steam manifold and pipeline cost (per acre)

Resource Dependant Annual Operating Costs for Crude Oil

Injection Costs: Incremental costs are added for secondary injection wells. These costs include pump operating, remedial services, workover rig services, and associated labor.

$$OPINJ\_W = OPINJK_{r,d} + (OPINJA_{r,d} * DEPTH) + (OPINJ\ B_{r,d} * DEPTH^2) + (OPINJ\ C_{r,d} * DEPTH^3) \tag{2-42}$$

where

OPINJ_W	=	Variable annual operating cost for injection (K$/Well)
R	=	Region number
D	=	Depth category number
OPINJA, B, C, K	=	Coefficients for variable annual operating cost for injection equation
DEPTH	=	Well depth

Injectant Cost: The injectant costs are added for the secondary injection wells. These costs are specific to the recovery method selected for the project. Three injectants are modeled: polymer, CO_2 from natural sources, and CO_2 from industrial sources.

Polymer Cost:

$$POLYCOST = POLYCOST * FPLY \tag{2-43}$$

where

POLYCOST	=	Cost of polymer ($/Lb)
FPLY	=	Energy elasticity factor for polymer

Natural CO_2 Cost: Cost to drill, produce and ship CO_2 from natural sources, namely CO_2 fields in Western Texas.

$$CO2COST = CO2K + (CO2B * OILPRICEO(1)) \tag{2-44}$$

$$CO2COST = CO2COST * CO2PR(IST) \tag{2-45}$$

where

CO2COST	=	Cost of natural CO_2 ($/Mcf)
IST	=	State identifier
CO2K, CO2B	=	Coefficients for natural CO_2 cost equation
OILPRICEO(1)	=	Crude oil price for first year of project analysis
CO2PR	=	State CO_2 cost multiplier used to represent changes in cost associated with transportation outside of the Permian Basin

Industrial CO_2 Cost: Cost to capture and transport CO_2 from industrial sources. These costs include the capture, compression to pipeline pressure, and the transportation to the project site via pipeline. The regional costs, which are specific to the industrial source of CO_2, are exogenously determined and provided in the input file.

Industrial CO_2 sources include

- Hydrogen Plants
- Ammonia Plants
- Ethanol Plants
- Cement Plants
- Hydrogen Refineries
- Power Plants
- Natural Gas Processing Plants
- Coal to Liquids

After unit costs have been calculated for the project, they are adjusted using technology levers as well as CPI multipliers. Two types of levers are applied to the costs. The first is the fractional change in cost associated with a new technology. The second is the incremental cost associated with implementing the new technology. These factors are determined by the model user. As an example,

$$NPR\_W = (NPR\_W * CHG\_FAC\_FAC(ITECH)) + CST\_FAC\_FAC(ITECH) \quad (2\text{-}46)$$

where,

NPR_W	=	Cost to equip a new oil producer (K$/well)
CHG_FAC_FAC	=	Fractional change in cost associated with technology improvements
CST_FAC_FAC	=	Incremental cost to apply the new technology
ITECH	=	Technology case (Base or Advanced)

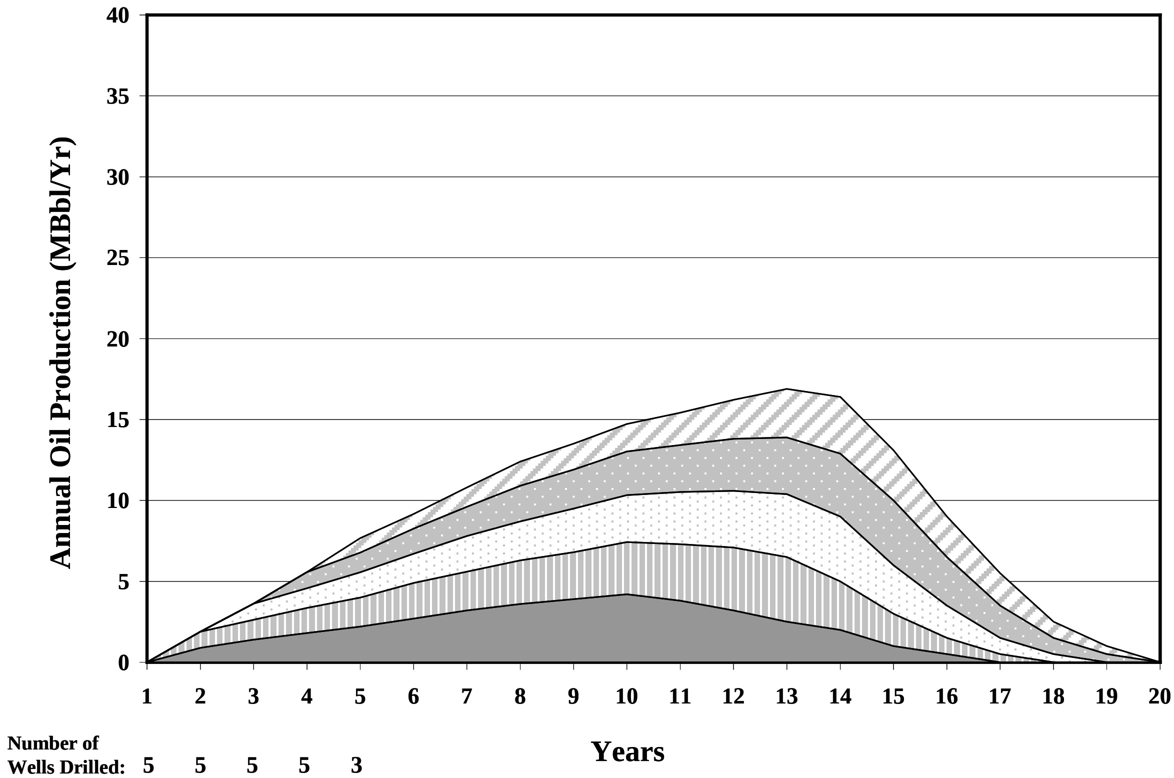
Determining Technical Production

The development schedule algorithms determine how the project's development over time will be modeled. They calculate the number of patterns initiated per year and the economic life of the well. The economic life is the number of years in which the revenue from production exceeds the costs required to produce the crude oil and natural gas.

The model then aggregates the well-level production of crude oil, natural gas, water, and injectant based upon the pattern life and number of wells initiated each year. The resulting profile is the technical production for the project.

Figure 2-8 shows the crude oil production for one project over the course of its life. The graph shows a hypothetical project. In this scenario patterns are initiated for five years. Each shaded area is the annual technical production associated with the initiated patterns.

Figure 2-8: Calculating Project Level Technical Production



The first step in modeling the technical production is to calculate the number of patterns drilled each year. The model uses several factors in calculating the development schedule:

- Potential delays between the discovery of the project and actual initiation
- The process modeled
- The resource access – the number of patterns developed each year is reduced if the resource is subject to cumulative surface use limitations
- The total number of patterns in the project
- The crude oil and natural gas prices
- The user specified maximum and minimum number of patterns developed each year
- The user specified percentage of the project to be developed each year
- The percentage of the project which is using base or advanced technology.

These apply to the EOR/ASR projects as well as the undiscovered and currently developing ones. The projects in existing fields and reservoirs are assumed to have all of their patterns – the number of active wells – developed in the first year of the project.

After calculating the number of patterns initiated each year, the model calculates the number of patterns which are active for each year of the project life.

Production Profile of the Project: For all EOR/ASR, undiscovered, and developing processes, the project level technical production is calculated using well-level production profiles. For infill projects, the production is doubled because the model assumes that there are two producers in each pattern.

$$OILPROD_{iyr1} = OILPROD_{iyr1} + (OPROD_{kyr} * PATN_{iyr}) \quad (2\text{-}47)$$
$$GASPROD_{iyr1} = OILPROD_{iyr1} + (GPROD_{kyr} * PATN_{iyr}) \quad (2\text{-}48)$$
$$NGLPROD_{iyr1} = NGLPROD_{iyr1} + (NPROD_{kyr} * PATN_{iyr}) \quad (2\text{-}49)$$
$$WATPROD_{iyr1} = WATPROD_{iyr1} + (WPROD_{kyr} * PATN_{iyr}) \quad (2\text{-}50)$$
$$TOTINJ_{iyr1} = TOTINJ_{iyr1} + (OINJ_{kyr} * PATN_{iyr}) \quad (2\text{-}51)$$
$$WATINJ_{iyr1} = WATINJ_{iyr1} + (WINJ_{kyr} * PATN_{iyr}) \quad (2\text{-}52)$$
$$TORECY_{iyr1} = TORECY_{iyr1} + (ORECY_{kyr} * PATN_{iyr}) \quad (2\text{-}53)$$
$$SUMP_{iyr1} = SUMP_{iyr1} + PATN_{iyr} \quad (2\text{-}54)$$

where

IYR1	=	Number of years
IYR	=	Year of project development
JYR	=	Number of years the project is developed
KYR	=	Year (well level profile)
LYR	=	Last project year in which pattern level profile is applied
OPROD	=	Pattern level annual crude oil production
GPROD	=	Pattern level annual natural gas production
NPROD	=	Pattern level annual NGLl production
WPROD	=	Pattern level annual water production
WINJ	=	Pattern level annual water injection
OINJ	=	Pattern level annual injectant injection
ORECY	=	Pattern level annual injectant recycled
PATN	=	Number of patterns initiated each year
SUMP	=	Cumulative number of patterns developed
OILPROD	=	Project level annual crude oil production
GASPROD	=	Project level annual natural gas production
NGLPROD	=	Project level annual NGL production
WATPROD	=	Project level annual water production
WATINJ	=	Project level annual water injection
TOTINJ	=	Project level annual injectant injection
TORECY	=	Project level annual injectant recycled

Reviewer's note: The equations above are confusing, because the same variable appears on the LHS and RHS. I'm guessing that the variable is simply being incremented on an annual basis, i.e., that the first equation should read something like

In any case, please clarify what is happening in the equations and use a new variable name on the LHS.

Resource Accounting

OLOGSS incorporates a complete and representative description of the processes by which crude oil and natural gas in the technically recoverable resource base[1] are converted to proved reserves.[2]

OLOGSS distinguishes between drilling for new fields (new field wildcats) and drilling for additional deposits within old fields (other exploratory and developmental wells). This enhancement recognizes important differences in exploratory drilling, both by its nature and in its physical and economic returns. New field wildcats convert resources in previously undiscovered fields[3] into both proved reserves (as new discoveries) and inferred reserves.[4] Other exploratory drilling and developmental drilling add to proved reserves from the stock of inferred reserves. The phenomenon of reserves appreciation is the process by which initial assessments of proved reserves from a new field discovery grow over time through extensions and revisions.

End of Year Reserves: The model calculates two types of end of year (EOY) reserves at the project level: inferred reserves and proved reserves. Inferred reserves are calculated as the total technical production minus the technical production from patterns initiated through a particular year. Proved reserves are calculated as the technical production from wells initiated through a particular year minus the cumulative production from those patterns.

Inferred reserves = total technical production – technical production for wells initiated

$$\text{airsvoil(ires, n)} = \sum_{`i=1}^{max\_yr}\left[\sum_{j=1}^{ilife}\big(\text{oprod}(j)\big)\times \text{patn}(i)\right] - \sum_{i=1}^{n}\left[\sum_{j=1}^{ilife}\big(\text{oprod}(j)\big)\times \text{patn}(i)\right] \quad (2\text{-}55)$$

$$\text{airsvgas(ires, n)} = \sum_{`i=1}^{max\_yr}\left[\sum_{j=1}^{ilife}\big(\text{gprod}(j)\big)\times \text{patn}(i)\right] - \sum_{i=1}^{n}\left[\sum_{j=1}^{ilife}\big(\text{gprod}(j)\big)\times \text{patn}(i)\right]$$

(2-56)

Reviewers note: It's not clear what "ires" is above. Also, it looks like all of these equations can be simplified by writing the outer sums from n+1 to max_yr, e.g.,

Proved reserves = technical production for patterns initiated – cumulative production

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[1] *Technically recoverable resources* are those volumes considered to be producible with current recovery technology and efficiency but without reference to economic viability. Technically recoverable volumes include proved reserves, inferred reserves, as well as undiscovered and other unproved resources. These resources may be recoverable by techniques considered either conventional or unconventional.

[2] *Proved reserves* are the estimated quantities that analyses of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[3] *Undiscovered resources* are located outside of oil and gas fields, in which the presence of resources has been confirmed by exploratory drilling, and thus exclude reserves and reserve extensions; however, they include resources from undiscovered pools within confirmed fields to the extent that such resources occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[4] *Inferred reserves* are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves.

$$\text{aresvoil(ires, n)} = \sum_{`i=1}^{n}\left[\sum_{j=1}^{ilife}\left(\text{oprod}(j)\right)\times\text{patn}(i)\right]-\sum_{i=1}^{n}\left[\sum_{j=1}^{n}\left(\text{oprod}(j)\right)\times\text{patn}(i)\right] \quad (2\text{-}57)$$

$$\text{aresvgas(ires, n)} = \sum_{`i=1}^{n}\left[\sum_{j=1}^{ilife}\left(\text{gprod}(j)\right)\times\text{patn}(i)\right]-\sum_{i=1}^{n}\left[\sum_{j=1}^{n}\left(\text{gprod}(j)\right)\times\text{patn}(i)\right] \quad (2\text{-}58)$$

where,

I, J	=	Years
N	=	Current year evaluated
ILIFE	=	Pattern life
MAX_YR	=	Maximum number of years
OPROD	=	Pattern level annual crude oil production
GPROD	=	Pattern level annual natural gas production
PATN	=	Number of patterns developed each year
AIRSVOIL	=	Annual inferred crude oil reserves
AIRSVGAS	=	Annual inferred natural gas reserves
ARESVOIL	=	Annual proved oil reserves
ARESVGAS	=	Annual proved natural gas reserves

For existing crude oil and natural gas projects, the model calculates the proved reserves. For these processes, the proved reserves are defined as the total technical production divided by the life of the project.

Calculating Project Costs

The model uses four drilling categories for the calculation of drilling and facilities costs. These categories are:

- New producers
- New injectors
- Conversions of producers to injectors
- Conversions of primary wells to secondary wells.

The number of ??? in each category required for the pattern is dependent upon the process and the project.

Project Level Process Independent Costs

Drilling costs and facility costs are determined at the project level.

Drilling Costs: Drilling costs are calculated using one of four approaches, depending on the resource and recovery process. These approaches apply to the following resources:

- Undiscovered crude oil and natural gas
- Existing crude oil and natural gas fields
- EOR/ASR projects
- Developing natural gas projects

<u>For undiscovered crude oil and natural gas resources:</u> The first well drilled in the first year of the project is assumed to be a wildcat well. The remaining wells are assumed to be undiscovered development wells. This is reflected in the application of the dryhole rates.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUE_R) * 1.0 * XPP1 \quad (2\text{-}59)$$

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUD_R) * (PATN_{iyr} – 1 * XPP1) \quad (2\text{-}60)$$

For existing crude oil and natural gas fields: As the field is already established, the developmental dryhole rate is used.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYKD_R) * (PATDEV_{ires,iyr,\ itech} * XPP1) \quad (2\text{-}61)$$

For EOR/ASR Projects: As the project is in an established and known field, the developmental dryhole rate is used.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYKD_R) * (PATN_{iyr} * XPP1) \quad (2\text{-}62)$$

For developing natural gas projects: As the project is currently being developed, it is assumed that the wildcat well(s) have previously been drilled. Therefore, the undiscovered developmental dryhole rate is applied to the project.

$$DRL\_CST2_{iyr} = DRL\_CST2_{iyr} + (DWC\_W + DRY\_W * REGDRYUD_R) * (PATN_{iyr} * XPP1) \quad (2\text{-}63)$$

where

IRES	=	Project index number
IYR	=	Year
R	=	Region
PATDEV	=	Number of patterns initiated each year for base and advanced technology cases
PATN	=	Annual number of patterns initiated
DRL_CST2	=	Technology case specific annual drilling cost
DWC_W	=	Cost to drill and complete a well
DRY_W	=	Cost to drill a dryhole
REGDRYUE	=	Dryhole rate for undiscovered exploration (wildcat)
REGDRYUD	=	Dryhole rate for undiscovered development
REGDRYKD	=	Dryhole rate for known fields development
XPP1	=	Number of producing wells drilled per pattern

Facilities Costs: Facilities costs depend on both the process and the resource. Five approaches are used to calculate the facilities costs for the project.

For undiscovered and developing natural gas projects:

$$FACCOST_{iyr} = FACCOST_{iyr} + (FWC\_W * PATN_{iyr} * XPP1) \quad (2\text{-}64)$$

For existing natural gas fields:

$$FACCOST_{iyr} = FACCOST_{iyr} + (FWC\_W * (PATDEV_{IRES,iyr,\ itech}) * XPP1) \quad (2\text{-}65)$$

For undiscovered continuous crude oil:

$$FACCOST_{iyr} = FACCOST_{iyr} + (NPR\_W * PATN_{iyr} * XPP1) \quad (2\text{-}66)$$

For existing crude oil fields:

$$\begin{aligned} FACCOST_{iyr} = FACCOST_{iyr} &+ (PSW\_W * (PATDEV_{IRES,iyr,\ itech}) * XPP4) \\ &+ (PSI\_W * PATDEV_{IRES,iyr,\ itech} * XPP3) \\ &+ (FAC\_W * PATDEV_{IRES,iyr,\ itech} * (XPP1 + XPP2)) \end{aligned} \quad (2\text{-}67)$$

For undiscovered conventional crude oil and EOR/ASR projects:

$$\begin{aligned} FACCOST_{iyr} = FACCOST_{iyr} &+ (PSW\_W * PATN_{iyr} * XPP4) \\ &+ (PSI\_W * PATN_{iyr} * XPP3) + (FAC\_W * PATN_{iyr} * (XPP1 + XPP2)) \end{aligned} \quad (2\text{-}68)$$

where

IYR	=	Year
IRES	=	Project index number
ITECH	=	Technology case
PATN	=	Number of patterns initiated each year for the technology case being evaluated
PATDEV	=	Number of patterns initiated each year for base and advanced technology cases
XPP1	=	Number of new production wells drilled per pattern
XPP2	=	Number of new injection wells drilled per pattern
XPP3	=	Number of producers converted to injectors per pattern
XPP4	=	Number of primary wells converted to secondary wells per pattern
FAC_W	=	Crude oil well facilities upgrade cost
NPR_W	=	Cost to equip a new producer
PSW_W	=	Cost to convert a primary well to a secondary well
PSI_W	=	Cost to convert a production well to an injection well
FWC_W	=	Natural gas well facilities cost
FACCOST	=	Annual facilities cost for the well

Injectant Cost Added to Operating and Maintenance: The cost of injectant is calculated and added to the operating and maintenance costs.

$$INJ_{iyr} = INJ_{iyr} + INJ\_OAM1 * WATINJ_{iyr} \quad (2\text{-}69)$$

where

IYR	=	Year

INJ	=	Annual injection cost
INJ_OAM1	=	Process specific cost of injection ($/Bbl)
WATINJ	=	Annual project level water injection

Fixed Annual Operating Costs for Crude Oil:
For CO_2 EOR:

$$AOAM_{iyr} = AOAM_{iyr} + OPSEC\_W * SUMP_{iyr} \tag{2-70}$$

For undiscovered conventional crude oil:

Fixed annual operating costs for secondary oil wells are assumed to be zero.

For all crude oil processes except CO_2 EOR:

$$AOAM_{iyr} = AOAM_{iyr} + (OMO\_W * XPATN_{iyr}) + (OPSEC\_W * XPATN_{iyr}) \tag{2-71}$$

Fixed Annual Operating Costs for Natural Gas:
For existing natural gas fields:

$$AOAM_{iyr} = AOAM_{iyr} + (FOAMG\_W * OAM\_M_{iyr} * XPATN_{iyr}) \tag{2-72}$$

For undiscovered and developing natural gas resources:

$$AOAM_{iyr} = AOAM_{iyr} + (FOAMG\_W * OAM\_M_{iyr} * XPATN_{iyr}) * XPP1 \tag{2-73}$$

where,

AOAM	=	Annual fixed operating an maintenance costs
IYR	=	Year
SUMP	=	Total cumulative patterns initiated
OPSEC_W	=	Fixed annual operating costs for secondary oil wells
OMO_W	=	Fixed annual operating costs for crude oil wells
FOAMG_W	=	Fixed annual operating costs for natural gas wells
OAM_M	=	Energy elasticity factor for operating and maintenance costs
XPATN	=	Annual number of active patterns
XPP1	=	Number of producing wells drilled per pattern

Variable Operating Costs:

$$OAM_{iyr} = OAM_{iyr} + (OILPROD_{iyr} * OIL\_OAM1 * OAM\_M_{iyr}) + (GASPROD_{iyr} * GAS\_OAM1 * OAM\_M_{iyr}) + (WATPROD_{iyr} * WAT\_OAM1 * OAM\_M_{iyr}) \tag{2-74}$$

$$STIM_{iyr} = STIM_{iyr} + (0.2 * STIM\_W * XPATN_{iyr} * XPP1) \tag{2-74}$$

For infill drilling: Injectant costs are zero.

$$OAM_{iyr} = OAM_{iyr} + INJ_{iyr} \tag{2-75}$$

where

OAM	=	Annual variable operating and maintenance costs
OILPROD	=	Annual project level crude oil production
GASPROD	=	Annual project level natural gas production
WATPROD	=	Annual project level water injection
OIL_OAM1	=	Process specific cost of crude oil production ($/Bbl)
GAS_OAM1	=	Process specific cost of natural gas production ($/Mcf)
WAT_OAM1	=	Process specific cost of water production ($/Bbl)
OAM_M	=	Energy elasticity factor for operating and maintenance costs
STIM	=	Project stimulation costs
STIM_W	=	Well stimulation costs
INJ	=	Cost of injection
XPATN	=	Annual number of active patterns
IYR	=	Year
XPP1	=	Number of producing wells drilled per pattern

Cost of Compression (Natural Gas Processes):

Installation costs:

$$COMP_{IYR} = COMP_{IYR} + (COMP\_W*PATN_{IYR}*XPP1) \tag{2-76}$$

O&M cost for compression:

$$OAM\_COMP_{IYR} = OAM\_COMP_{IYR} + (GASPROD_{IYR} * COMP\_OAM *OAM\_M_{IYR}) \tag{2-77}$$

where

COMP	=	Cost of installing natural gas compression equipment
COMP_W	=	Natural gas compression cost
PATN	=	Number of patterns initiated each year
IYR	=	Year
XPP1	=	Number of producing wells drilled per pattern
OAM_COMP	=	Operating and maintenance costs for natural gas compression
GASPROD	=	Annual project level natural gas production
COMP_OAM	=	Compressor O & M costs
OAM_M	=	Energy elasticity factor for operating and maintenance costs

Process Dependent Costs

Process-specific facilities and capital costs are calculated at the project level.

Facilities Costs

Profile Model: The facilities cost of a water handling plant is added to the first year facilities costs.

$$FACCOST_1 = FACCOST_1 + PWHP * \left(\frac{RMAX}{365}\right) \qquad (2\text{-}78)$$

where

$FACCOST_1$	=	First year of project facilities costs
PWHP	=	Produced water handling plant multiplier
RMAX	=	Maximum annual water injection rate

Polymer Model: The facilities cost for a water handling plant is added to the first year facilities costs.

$$FACCOST_1 = FACCOST_1 + PWP\_F \qquad (2\text{-}79)$$

where

$FACCOST_1$	=	First year of project facilities costs
PWP_F	=	Produced water handling plant

Advanced CO_2: Other costs added to the facilities costs include the facilities cost for a CO_2 handling plant and a recycling plant, the O&M cost for a CO_2 handling plant and recycling plant, injectant cost, O&M and fixed O&M costs for a CO_2 handling plant and a recycling plant. If the plant is developed in a single stage, the costs are added to the first year of the facilities costs. If a second stage is required, the additional costs are added to the sixth year of facilities costs.

$$FACCOST1 = FACCOST1 + \left(CO2RK * \left(\frac{0.75 * RMAX}{365}\right)^{CO2RB}\right) * 1{,}000 \qquad (2\text{-}80)$$

$$FACCOST6 = FACCOST6 + \left(CO2RK * \left(\frac{0.75 * RMAX}{365}\right)^{CO2RB}\right) * 1{,}000$$

$$INJ_{iyr} = INJ_{iyr} + (TOTINJ_{iyr} - TORECY_{iyr}) * CO2COST \qquad (2\text{-}81)$$

$$OAM_{iyr} = OAM_{iyr} + (OAM\_M_{iyr} * TORECY_{iyr}) * (CO2OAM + PSW\_W * 0.25) \qquad (2\text{-}82)$$

$$FOAM_{iyr} = (FOAM_{iyr} + TOTINJ_{iyr}) * 0.40 * FCO2 \qquad (2\text{-}83)$$

$$TORECY\_CST_{iyr} = TORECY\_CST_{iyr} + (TORECY_{iyr} * CO2OAM2 * OAM\_M_{iyr}) \qquad (2\text{-}84)$$

where

IYR	=	Year
RMAX	=	Maximum annual volume of recycled CO_2

CO2OAM	=	O & M cost for CO_2 handling plant
CO2OAM2	=	The O & M cost for the project's CO_2 injection plant
CO2RK, CO2RB	=	CO_2 recycling plant cost coefficients
INJ	=	Cost of purchased CO_2
TOTINJ	=	Annual project level volume of injected CO_2
TORECY	=	Annual project level CO_2 recycled volume
CO2COST	=	Cost of CO_2 ($/mcf)
OAM	=	Annual variable operating and maintenance costs
OAM_M	=	Energy elasticity factor for operating and maintenance costs
FOAM	=	Fixed annual operating and maintenance costs
FCO2	=	Energy elasticity factor for CO_2
FACCOST	=	Annual project facilities costs
TORECY_CST	=	The annual cost of operating the CO_2 recycling plant

Steam Model: Facilities and O&M costs for steam generators and recycling.

Recalculate the facilities costs: Facilities costs include the capital cost for injection plants, which is based upon the OOIP of the project, the steam recycling plant, and the steam generators required for the project.

$$\begin{aligned} \mathrm{FACCOST1} &= \mathrm{FACCOST1} + \left(\frac{OOIP*0.1*2.0*APAT}{TOTPAT}\right) + (\mathrm{RECY\_WAT * RMAXWAT} \\ &\quad + \mathrm{RECY\_OIL * RMAXOIL}) + (\mathrm{STMMA * TOTPAT * PATSIZE}) \\ &\quad + (\mathrm{IGEN}_{iyr} - \mathrm{IG})\mathrm{* STMGA} \end{aligned} \tag{2-85}$$

$$\begin{aligned} \mathrm{OAM}_{iyr} &= \mathrm{OAM}_{iyr} + (\mathrm{WAT\_OAM1 * WATPROD}_{iyr} \mathrm{* OAM\_M}_{iyr}) + (\mathrm{OIL\_OAM1} \\ &\quad \mathrm{* OILPROD}_{iyr} \mathrm{* OAM\_M}_{iyr}) + (\mathrm{INJ\_OAM1 * WATINJ}_{iyr} \mathrm{* OAM\_M}_{iyr}) \end{aligned} \tag{2-86}$$

where

IYR	=	Year
IGEN	=	Number of active steam generators each year
IG	=	Number of active steam generators in previous year
FACCOST	=	Annual project level facilities costs
RMAXWAT	=	Maximum daily water production rate
RMAXOIL	=	Maximum daily crude oil production rate
APAT	=	Number of developed patterns
TOTPAT	=	Total number of patterns in the project
OOIP	=	Original oil in place (mmbbl)
PATSIZE	=	Pattern size (acres)
STMMA	=	Unit cost for steam manifolds
STMGA	=	Unit cost for steam generators
OAM	=	Annual variable operating and maintenance costs
OAM_M	=	Energy elasticity factor for operating and maintenance costs
WAT_OAM1	=	Process specific cost of water production ($/Bbl)
OIL_OAM1	=	Process specific cost of crude oil production ($/Bbl)

INJ_OAM1	=	Process specific cost of water injection ($/Bbl)
OILPROD	=	Annual project level crude oil production
WATPROD	=	Annual project level water production
WATINJ	=	Annual project level water injection
RECY_WAT	=	Recycling plant cost – water factor
RECY_OIL	=	Recycling plant cost – oil factor

Operating and Maintenance Cost

This subroutine calculates the process specific O&M costs.

Profile Model: Add the O&M costs of injected polymer.

$$INJ_{iyr} = INJ_{iyr} + \frac{OAM\_M_{iyr} * TOTINJ_{iyr} * POLYCOST}{1000} \quad (2\text{-}87)$$

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \quad (2\text{-}88)$$

where

IYR	=	Year
MAX_YR	=	Maximum number of years
INJ	=	Annual Injection cost
OAM_M	=	Energy elasticity factor for operating and maintenance cost
TOTINJ	=	Annual project level injectant injection volume
POLYCOST	=	Polymer cost
OAM	=	Annual variable operating and maintenance cost
XPATN	=	Number of active patterns
PSI_W	=	Cost to convert a primary well to an injection well

Polymer: Add the O&M costs of injected polymer.

$$INJ_{iyr} = INJ_{IYR} + \frac{TOTINJ_{iyr} * POLYCOST}{1{,}000} \quad (2\text{-}89)$$

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \quad (2\text{-}90)$$

where

IYR	=	Year
MAX_YR	=	Maximum number of years
INJ	=	Annual Injection cost
TOTINJ	=	Annual project level injectant injection volume
POLYCOST	=	Polymer cost
OAM	=	Annual variable operating and maintenance cost
XPATN	=	Number of active patterns
PSI_W	=	Cost to convert a primary well to an injection well

Waterflood: Add the O&M costs of water injected as well as the cost to convert a primary well to an injection well.

$$OAM_{iyr} = OAM_{iyr} + (XPATN_{iyr} * 0.25 * PSI\_W) \quad (2\text{-}91)$$

where

IYR	=	Year
MAX_YR	=	Maximum number of years
OAM	=	Annual variable operating and maintenance cost
XPATN	=	Number of active patterns
PSI_W	=	Cost to convert a primary well to an injection well

Existing crude oil fields and reservoirs: Since no new drilling or major investments are expected for decline, facilities and drilling costs are zeroed out.

$$OAM_{iyr} = OAM_{iyr} + ((OIL\_OAM1 * OILPROD_{iyr}) + (GAS\_OAM1 * GASPROD_{iyr}) + (WAT\_OAM1 * WATPROD_{iyr})) * OAM\_M_{iyr} \quad (2\text{-}92)$$

$$AOAM_{iyr} = AOAM_{iyr} + \left(\frac{OPSEC\_W * OAM\_M_{iyr} * SUMP_{iyr}}{5} \right) \quad (2\text{-}93)$$

where

IYR	=	Year
OILPROD	=	Annual project level crude oil production
GASPROD	=	Annual project level natural gas production
WATPROD	=	Annual project level water production
OIL_OAM1	=	Process specific cost of crude oil production ($/Bbl)
GAS_OAM1	=	Process specific cost of natural gas production ($/Mcf)
WAT_OAM1	=	Process specific cost of water production ($/Bbl)
OAM_M	=	Energy elasticity factor for operating and maintenance costs
OPSEC_W	=	Fixed annual operating cost for secondary well operations
SUMP	=	Cumulative patterns developed
AOAM	=	Fixed annual operating and maintenance costs
OAM	=	Variable annual operating and maintenance costs

Overhead Costs: : General and Administrative (G&A) costs on capitalized and expensed items, which consist of administration, accounting, contracting and legal fees/expenses for the project, are calculated according to the following equations:

$$GNA\_EXP_{itech} = GNA\_EXP_{itech} * CHG\_GNA\_FAC_{itech} \quad (2\text{-}94)$$

$$GNA\_CAP_{itech} = GNA\_CAP_{itech} * CHG\_GNA\_FAC_{itech} \quad (2\text{-}95)$$

where

ITECH	=	Technology case (base and advanced) number
GNA_EXP	=	The G&A rate applied to expensed items for the project
GNA_CAP	=	The G&A rate applied to capitalized items for the project
CHG_GNA_FAC	=	Technology case specific change in G&A rates

Timing

Overview of Timing Module

The timing routine determines which of the exploration and EOR/ASR projects are eligible for development in any particular year. Those that are eligible are subject to an economic analysis and passed to the project sort and development routines. The timing routine has two sections. The first applies to exploration projects while the second is applied to EOR/ASR and developing natural gas projects.

Figure 2-9 provides the overall logic for the exploration component of the timing routine. For each project regional crude oil and natural gas prices are obtained. The project is then examined to see if it has previously been timed and developed. The timed projects are no longer available and thus not considered.

The model uses four resource access categories for the undiscovered projects:

- No leasing due to statutory or executive order
- Leasing available but cumulative timing limitations between 3 and 9 months
- Leasing available but with controlled surface use
- Standard leasing terms

Each project has been assigned to a resource access category. If the access category is not available in the year evaluated, the project fails the resource access check.

After the project is evaluated, the number of considered projects is increased. Figure 2-10 shows the timing logic applied to the EOR/ASR projects as well as the developing natural gas projects.

Before the economics are evaluated, the prices are set and the eligibility is determined. The following conditions must be met:

- Project has not been previously timed
- Project must be eligible for timing, re-passed the economic pre-screening routine
- Corresponding decline curve project must have been timed. This does not apply to the developing natural gas projects.

If the project meets all of these criteria, then it is considered eligible for economic analysis. For an EOR/ASR project to be considered for timing, it must be within a process specific EOR/ASR development window. These windows are listed in Table 2-4.

Table 2-4: EOR/ASR Eligibility Ranges

Process	Before Economic Limit	After Economic Limit
CO_2 Flooding	After 2009	10 Years
Steam Flooding	5 Years	10 Years
Polymer Flooding	5 Years	10 Years
Infill Drilling	After 2009	7 Years
Profile Modification	5 Years	7 Years
Horizontal Continuity	5 Years	7 Years
Horizontal Profile	5 Years	7 Years
Waterflood	4 Years	6 Years

The economic viability of the eligible projects is then evaluated. A different analytical approach is applied to CO_2 EOR and all other projects. For non-CO_2 EOR projects the project is screened for applicable technology levers, and the economic analysis is conducted. CO_2 EOR projects are treated differently because of the different CO_2 costs associated with the different sources of industrial and natural CO_2.

For each available source, the economic variables are calculated and stored. These include the source of CO_2 and the project's ranking criterion.

Detailed description of timing module

Exploration projects: The first step in the timing module is to determine which reservoirs are eligible to be timed for conventional and continuous exploration. Prior to evaluation, the constraints, resource access, and technology and economic levers are checked, and the technology case is set.

Calculate economics for EOR/ASR and developing natural gas projects:
This section determines whether an EOR/ASR or developing natural gas project is eligible for economic analysis and timing. The following resources are processes considered in this step.
EOR Processes:

- CO_2 Flooding
- Steam Flooding
- Polymer Flooding
- Profile Modification

ASR Processes:

- Water Flooding
- Infill Drilling
- Horizontal Continuity
- Horizontal Profile

Developing natural gas

- Tight Gas
- Shale Gas
- Coalbed Methane

A project is eligible for timing if the corresponding decline curve project has previously been timed and the year of evaluation is within the eligibility window for the process, as listed in table 2-4.

Project Ranking: Sorts exploration and EOR/ASR projects which are economic for timing. The subroutine matches the discovery order for undiscovered projects and sorts the others by ranking criterion. The criteria include

- Net present value
- Investment efficiency
- Rate of return
- Cumulative discounted after tax cashflow

Selection and Timing: Times the exploration and EOR/ASR projects which are considered in that given year.

Project Selection

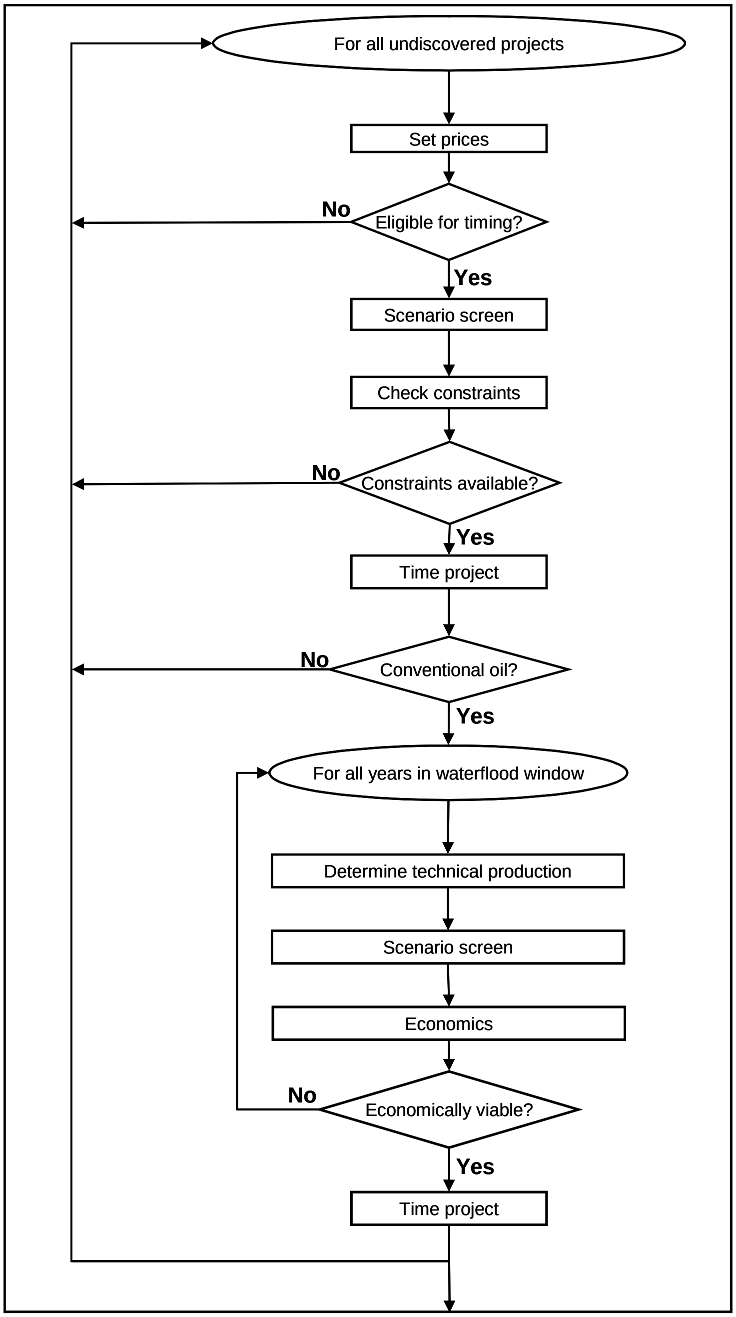
The project selection subroutine determines which exploration, EOR/ASR and developing natural gas projects will be modeled as developed in each year analyzed. In addition, the following development decisions are made:

- Waterflood of conventional undiscovered crude oil projects
- Extension of CO_2 floods as the total CO_2 injected is increased from 0.4 hydrocarbon pore volume (HCPV) to 1.0 HCPV

Overview of Project Selection

The project selection subroutine evaluates undiscovered projects separate from other projects. The logic for the development of exploration projects is provided in figure 2-9.

Figure 2-9: Selecting Undiscovered Projects



As illustrated in the figure the prices are set for the project before its eligibility is checked. Eligibility has the following requirements:

- Project is economically viable
- Project is not previously timed and developed

The projects which are eligible are screened for applicable technologies which impact the drilling success rates. The development constraints required for the project are checked against those that are available in the region.

If sufficient development resources are available, the project is timed and developed. As part of this process, the available development constraints are adjusted, the number of available accumulations is reduced and the results are aggregated. If no undiscovered accumulations remain, then the project is no longer eligible for timing. The projects that are eligible, economically viable, and undeveloped due to lack of development resources, are considered again for future projection years. If the project is conventional crude oil, it is possible to time a waterflood project.

The model evaluates the waterflood potential in a window centered upon the end of the economic life for the undiscovered project. For each year of that window, the technical production is determined for the waterflood project, applicable technology and economic levers are applied, and the economics are considered. If the waterflood project is economic, it is timed. This process is continued until either a waterflood project is timed or the window closes.

The second component of the project selection subroutine is applicable to EOR/ASR projects as well as the developing natural gas projects. The major steps applied to these projects are detailed in figures 2-10 and 2-11.

As seen in the flowchart, the prices are set for the project and the eligibility is checked. As with the undiscovered projects, the subroutine checks the candidate project for both economic viability and eligibility for timing. Afterwards, the project is screened for any applicable technology and economic levers.

If the project is eligible for CO_2 EOR, the economics are re-run for the specific source of CO_2. Afterwards, the availability of resource development constraints is checked for the project. If sufficient drilling and capital resources are available, the project preferences are checked.

The project preferences are rules which govern the competition between projects and selection of projects; these rules are listed below:

- CO_2 EOR and infill drilling are available after 2010
- Profile modification becomes available after 2011
- The annual number of infill drilling and profile modification projects is limited
- Horizontal continuity can compete against any other process except steam flood
- Horizontal profile can compete against any other process except steam flood or profile modification
- Polymer flooding cannot compete against any other process

If the project meets the technology preferences, then it is timed and developed. This process is different for CO_2 EOR and all other processes.

Figure 2-10: Selecting EOR/ASR projects

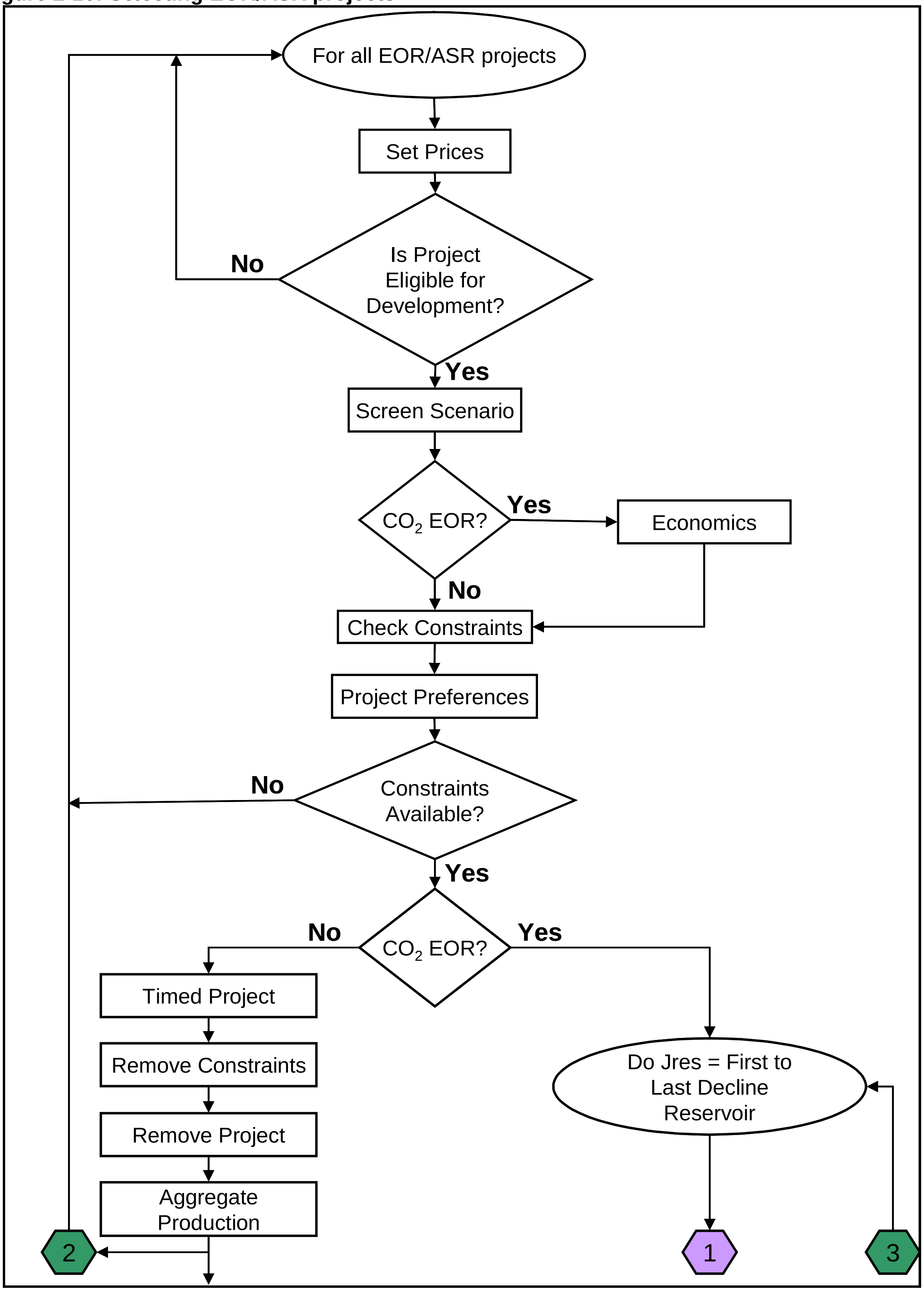
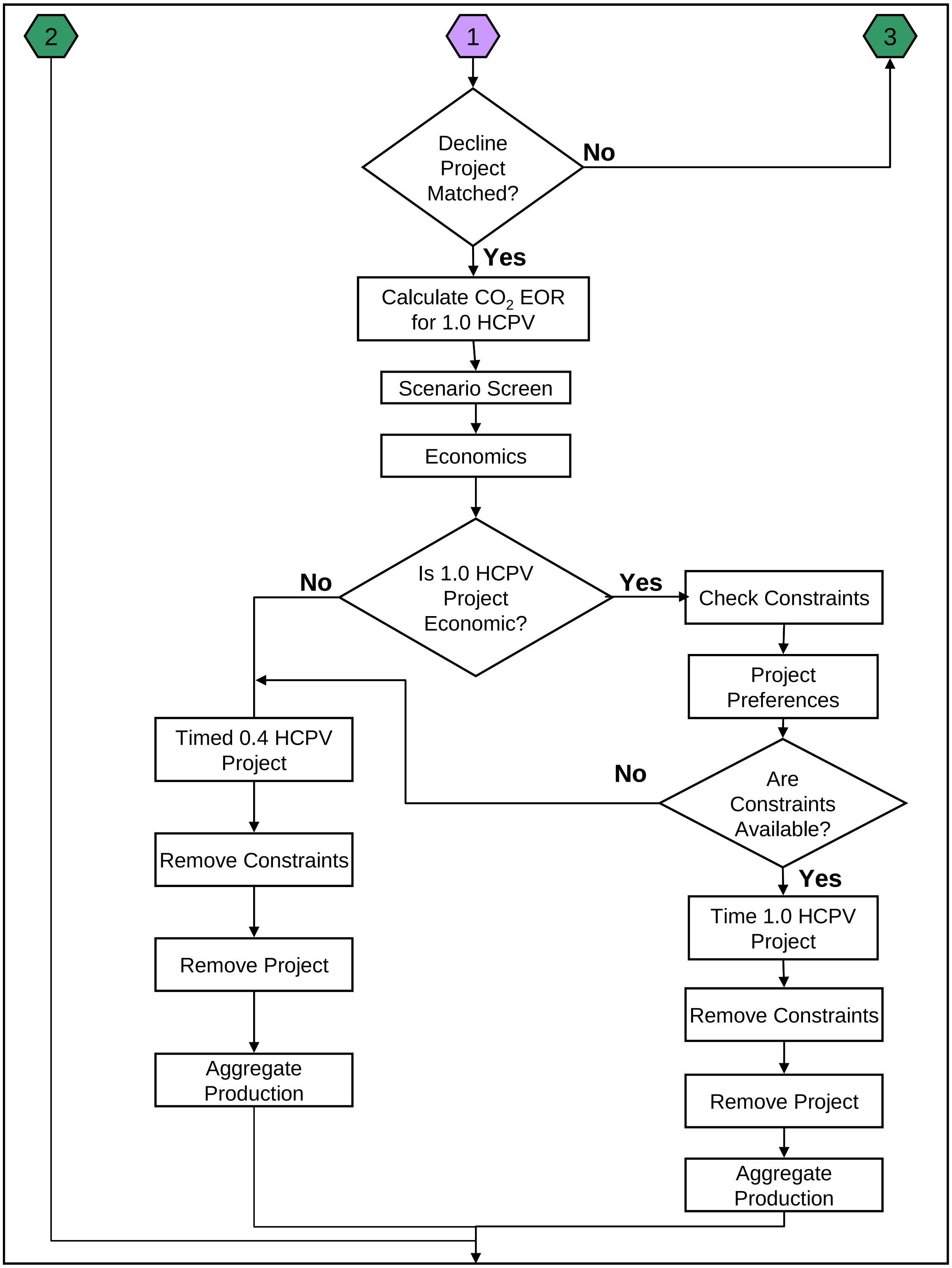


Figure 2-11: Selecting EOR/ASR projects, Continued



For non-CO_2 projects, the constraints are adjusted, the project is removed from the list of eligible projects, and the results are aggregated. It is assumed that most EOR/ASR processes are mutually exclusive and that a reservoir is limited to one process. There are a few exceptions:

- CO_2 EOR and infill drilling can be done in the same reservoir
- CO_2 EOR and horizontal continuity can be done in the same reservoir

For CO_2 EOR projects, a different methodology is used at this step: the decision to increase the total CO_2 injection from 0.4 hydrocarbon pore volume (HCPV) to 1.0 HCPV is made. The model performs the following steps, illustrated in figure 2-10 and continued in figure 2-11.

The CO_2 EOR project is matched to the corresponding decline curve project. Using the project-specific petro-physical properties, the technical production and injection requirements are determined for the 1.0 HCPV project. After applying any applicable technology and economic levers, the model evaluates the project economics. If the 1.0 HCPV project is not economically viable, then the 0.4 HCPV project is timed. If the 1.0 HCPV project is viable, the constraints and project preferences are checked. Assuming that there are sufficient development resources, and competition allows for the development of the project, then the model times the 1.0 HCPV project. If sufficient resources for the 1.0 HCPV project are not available, the model times the 0.4 HCPV project.

Detailed description of project selection

The project selection subroutine analyzes undiscovered crude oil and natural gas projects. If a project is economic and eligible for development, the drilling and capital constraints are examined to determine whether the constraints have been met. The model assumes that the projects for which development resources are available are developed.

Waterflood processing may be considered for undiscovered conventional crude oil projects. The waterflood project will be developed in the first year it is both eligible for implementation and the waterflood project is economically viable.

EOR/ASR Projects

When considering whether a project is eligible for EOR/ASR processing, the model first checks the availability of sufficient development resources are available. Based on the project economics and projected availability of development resources, it also decides whether or not to extend injection in CO_2 EOR projects from 0.4 HCPV to 1.0 HCPV.

If the 1.0 HCPV is economic but insufficient resources are available, the 0.4 HCPV project is selected instead. If the 1.0 HCPV project is uneconomic, the 0.4 HCPV project is selected.

Constraints

Resource development constraints are used during the selection of projects for development in order to mimic the infrastructure limitations of the oil and gas industry. The model assumes that only the projects that do not exceed the constraints available will be developed.

Types of constraints modeled

The development constraints represented in the model include drilling footage availability, rig depth rating, capital constraints, demand for natural gas, carbon dioxide volumes, and resource access.

In the remainder of this section, additional details will be provided for each of these constraints.

Drilling: Drilling constraints are bounding values used to determine the resource production in a given region. OLOGSS uses the following drilling categories:

- Developmental crude oil – applied to EOR/ASR projects
- Developmental natural gas – applied to developing natural gas projects
- Horizontal drilling – applied to horizontal wells
- Dual use – available for either crude oil or natural gas projects
- Conventional crude oil exploration – applied to undiscovered conventional crude oil projects
- Conventional natural gas exploration – applied to undiscovered conventional natural gas projects
- Continuous crude oil exploration – applied to undiscovered continuous crude oil projects
- Continuous natural gas exploration – applied to undiscovered continuous natural gas projects

Except for horizontal drilling, which is calculated as a fraction of the national developmental crude oil footage, all categories are calculated at the national level and apportioned to the regional level. Horizontal drilling is at the national level.

The following equations are used to calculate the national crude oil development drilling. The annual footage available is a function of lagged five year average crude oil prices and the total growth in drilling.

The total growth in drilling is calculated using the following algorithm.
<u>For the first year:</u>

$$\text{TOT\_GROWTH} = 1.0 * \left(1.0 + \frac{\text{DRILL\_OVER}}{100}\right) \tag{2-96}$$

<u>For the remaining years:</u> (2-97)

$$\text{TOT\_GROWTH} = \left(\left(\text{TOT\_GROWTH} * \left(1.0 + \frac{\text{RGR}}{100}\right)\right) - \left(\text{TOT\_GROWTH} * \left(1.0 + \frac{\text{RGR}}{100}\right)\right) * \left(\frac{\text{RRR}}{100}\right)\right) * \left(1.0 * \frac{\text{DRILL\_OVER}}{100}\right)$$

Reviewers note: The equation above would be clearer if it were written as

where

IYR	=	Year evaluated
MAX_YR	=	Maximum number of years
TOT_GROWTH	=	Annual growth change for drilling at the national level (fraction)
DRILL_OVER	=	Percent of drilling constraint available for footage over run
RGR	=	Annual rig development rate (percent)
RRR	=	Annual rig retirement rate (percent)

The national level crude oil and natural gas development footage available for drilling is calculated using the following equations. The coefficients for the drilling footage equations were estimated by least squares using model equations 2.B-16 and 2.B-17 in Appendix 2.B.

$$NAT\_OIL_{IYR} = (OILA0 + OILA1 * OILPRICED_{IYR}) * TOTMUL * TOT\_GROWTH * OIL\_ADJ_{IYR} \qquad (2\text{-}98)$$

$$NAT\_GAS_{IYR} = (GASA0 + GASA1 * GASPRICED_{IYR}) * TOTMUL * TOT\_GROWTH * GAS\_ADJ_{IYR} \qquad (2\text{-}99)$$

where

IYR	=	Year evaluated
TOT_GROWTH	=	Final calculated annual growth change for drilling at the national level
NAT_OIL NAT_GAS	=	National development footage available (Thousand Feet)
OILA0,1 GASA0,1	=	Footage equation coefficients
OILPRICED GASPRICED	=	Annual prices used in drilling constraints, five year average
TOTMUL	=	Total drilling constraint multiplier
OIL_ADJ GAS_ADJ	=	Annual crude oil, natural gas developmental drilling availability factors

After the available footage for drilling is calculated at the national level, regional allocations are used to allocate the drilling to each of the OLOGSS regions. The drilling which is not allocated, due to the “drill_trans” factor, is available in any region and represents the drilling which can be transferred among regions. The regional allocations are then subtracted from the national availability.

$$REG\_OIL_{j,iyr} = NAT\_OIL_{IYR} * \left(\frac{PRO\_REGOIL_J}{100}\right) * \left(1.0 - \frac{DRILL\_TRANS}{100}\right) \qquad (2\text{-}100)$$

where

J	=	Region number
IYR	=	Year

REG_OIL	=	Regional development oil footage (Thousand Feet) available in a specified region
NAT_OIL	=	National development oil footage (Thousand Feet). After allocation, the footage transferrable among regions.
PRO_REGOIL	=	Regional development oil footage allocation (percent)
DRILL_TRANS	=	Percent of footage that is transferable among regions

Footage Constraints: The model determines whether there is sufficient footage available to drill the complete project. The drilling constraint is applied to all projects. Footage requirements are calculated in two stages: vertical drilling and horizontal drilling. The first well for an exploration project is assumed to be a wildcat well and uses a different success rate than the other wells in the project. The vertical drilling is calculated using the following formula.

For non-exploration projects:

$$FOOTREQ_{ii} = (DEPTH_{itech} * (1.0 + SUC\_RATEKD_{itech})) * PATDEV_{irs,ii-itimeyr+1,itech} * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (DEPTH_{itech} * PATDEV_{irs,ii-itiimeyr+1,itech}) * 0.5 * ATOTCONV_{irs,itech} \quad (2\text{-}101)$$

For exploration projects:

For the first year of the project (2-102)

$$FOOTREQ_{ii} = (DEPTH_{itech} * (1.0 + SUC\_RATEUE_{itech})) * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (0.5 * ATOTCONV_{irs,itech}) + (DEPTH_{itech} * (1.0 + SUC\_RATEUD_{itech})) * (PATDEV_{irs,ii-itimeyr+1,itech} - 1 * ATOTPROD_{irs,itech} + ATOTINJ_{ir,itech} + 0.5 * ATOTCONV_{irs,itech})$$

For all other project years (2-103)

$$FOOTREQ_{ii} = (DEPTH_{itech} * (1.0 + SUC\_RATEUD_{itech})) * PATDEV_{irs,ii-itimeyr+1,itech} * (ATOTPROD_{irs,itech} + ATOTINJ_{irs,itech}) + (DEPTH_{itech} * PATDEV_{irs,ii-itimeyr+1,itech} * 0.5 * ATOTCONV_{irs,itech})$$

where

irs	=	Project index number
itech	=	Technology index number
itimeyr	=	Year in which project is evaluated for development
ii	=	Year evaluated
FOOTREQ	=	Footage required for drilling (Thousand Feet)
DEPTH	=	Depth of formation (Feet)
SUC_RATEKD	=	Success rate for known development
SUC_RATEUE	=	Success rate for undiscovered exploration (wildcat)
SUC_RATEUD	=	Success rate for undiscovered development
PATDEV	=	Annual number of patterns developed for base and advanced technology
ATOTPROD	=	Number of new producers drilled per pattern
ATOTINJ	=	Number of new injectors drilled per patterns
ATOTCONV	=	Number of conversions from producing to injection wells per pattern

Add Laterals and Horizontal Wells: The lateral length and the horizontal well length are added to the footage required for drilling.

$$FOOTREQii = FOOTREQii + (ALATNUM_{irs,itech} * ALATLEN_{irs,itech} * (1.0 + SUC\_RATEKD_{itech}) * PATDEV_{irs,ii-itimeyr+1,itech}) \quad (2\text{-}104)$$

where

irs	=	Project index number
itech	=	Technology index number
itimeyr	=	Year in which project is evaluated for development
ii	=	Year evaluated
FOOTREQ	=	Footage required for drilling (Feet)
ALATNUM	=	Number of laterals
ALATLEN	=	Length of laterals (Feet)
SUC_RATEKD	=	Success rate for known development
PATDEV	=	Annual number of patterns developed for base and advanced technology

After determining the footage requirements, the model calculates the footage available for the project. The available footage is specific to the resource, the process, and the constraint options which have been specified by the user. If the footage required to drill the project is greater than the footage available then the project is not feasible.

Rig depth rating: The rig depth rating is used to determine whether a rig is available which can drill to the depth required by the project. OLOGSS uses the nine rig depth categories provided in table 2-5.

Table 2-5 Rig Depth Categories

Depth Category	Minimum Depth (Ft)	Maximum Depth (Ft)
1	1	2,500
2	2,501	5,000
3	5,001	7,500
4	7,501	10,000
5	10,001	12,500
6	12,501	15,000
7	15,001	17,500
8	17,251	20,000
9	20,001	Deeper

The rig depth rating is applied at the national level. The available footage is calculated using the following equation.

$$RDR\_FOOTAGE_{j,\ iyr} = (NAT\_TOT_{iyr} + NAT\_EXP_{iyr} + NAT\_EXPG_{iyr}) * \frac{RDR_j}{100} \quad (2\text{-}106)$$

where

J	=	Rig depth rating category
IYR	=	Year
RDR_FOOTAGE	=	Footage available in this interval (K Ft)

NAT_TOT	=	Total national developmental (crude oil, natural gas, and horizontal) drilling footage available (Thousand feet)
NAT_EXPG	=	National gas exploration drilling constraint
NAT_EXP	=	Total national exploration drilling footage available (Thousand feet)
RDR_j	=	Percentage of rigs which can drill to depth category j

Capital: Crude oil and natural gas companies use different investment and project evaluation criteria based upon their specific cost of capital, the portfolio of investment opportunities available, and their perceived technical risks. OLOGSS uses capital constraints to mimic limitations on the amount of investments the oil and gas industry can make in a given year. The capital constraint is applied at the national level.

Natural Gas Demand: Demand for natural gas is calculated at the regional level by the NGTDM and supplied to OLOGSS.

Carbon Dioxide: For CO_2 miscible flooding, availability of CO_2 gas from natural and industrial sources is a limiting factor in developing the candidate projects. In the Permian Basin, where the majority of the current CO_2 projects are located, the CO_2 pipeline capacity is a major concern.

The CO_2 constraint in OLOGSS incorporates both industrial and natural sources of CO_2. The industrial sources of CO_2 are ammonia plants, hydrogen plants, existing and planned ethanol plants, cement plants, refineries, fossil fuel power plants, and new IGCC plants.

Technology and market constraints prevent the total volumes of CO_2 produced from becoming immediately available. The development of the CO_2 market is divided into 3 periods:
1) technology R&D, 2) infrastructure construction, and 3) market acceptance. The capture technology is under development during the R&D phase, and no CO_2 produced by the technology is assumed available at that time. During the infrastructure development, the required capture equipment, pipelines, and compressors are being constructed, and no CO_2 is assumed available. During the market acceptance phase, the capture technology is being widely implemented and volumes of CO_2 are assumed to become available.

The maximum CO_2 available is achieved when the maximum percentage of the industry that will adopt the technology has adopted it. This provides an upper limit on the volume of CO_2 that will be available. The graph below provides the annual availability of CO_2 from ammonia plants. Availability curves were developed for each source of industrial, as well as natural CO_2.

CO_2 constraints are calculated at the regional level and are source specific.

Resource Access: Restrictions on access to Federal lands constrain the development of undiscovered crude oil and natural gas resources. OLOGSS uses four resource access categories:

- No leasing due to statutory or executive order
- Leasing available but cumulative timing limitations between 3 and 9 months
- Leasing available but with controlled surface use
- Standard leasing terms

The percentage of the undiscovered resource in each category was estimated using data from the Department of Interior's Basin Inventories of Onshore Federal Land's Oil and Gas Resources.

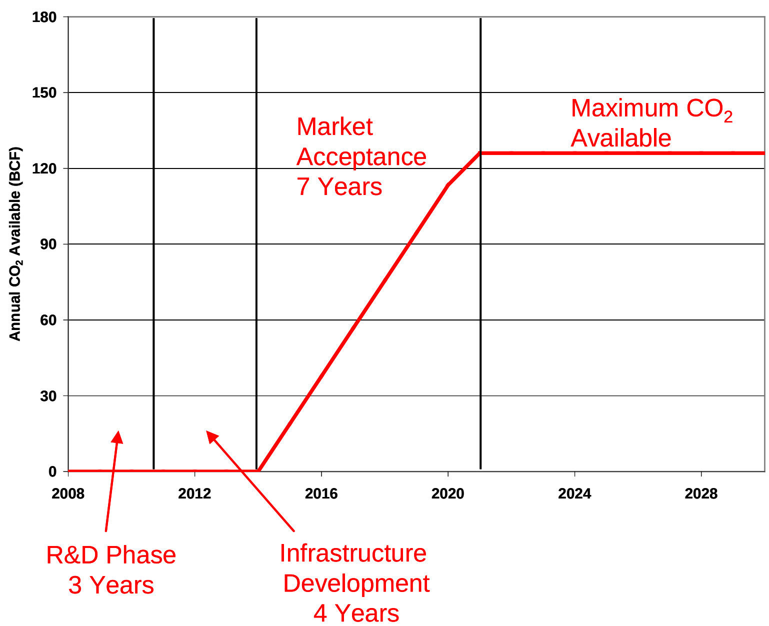


Figure 2-12: CO2 Market Acceptance Curve

Technology

Research and development programs are designed to improve technology to increase the amount of resources recovered from crude oil and natural gas fields. Key areas of study include methods of increasing production, extending reserves, and reducing costs. To optimize the impact of R & D efforts, potential benefits of a new technology are weighed against the costs of research and development. OLOGSS has the capability to model the effects of R & D programs and other technology improvements as they impact the production and economics of a project. This is done in two steps: (1) modeling the implementation of the technology within the oil and gas industry and (2) modeling the costs and benefits for a project that applies this technology.

Impact of technology on economics and recovery

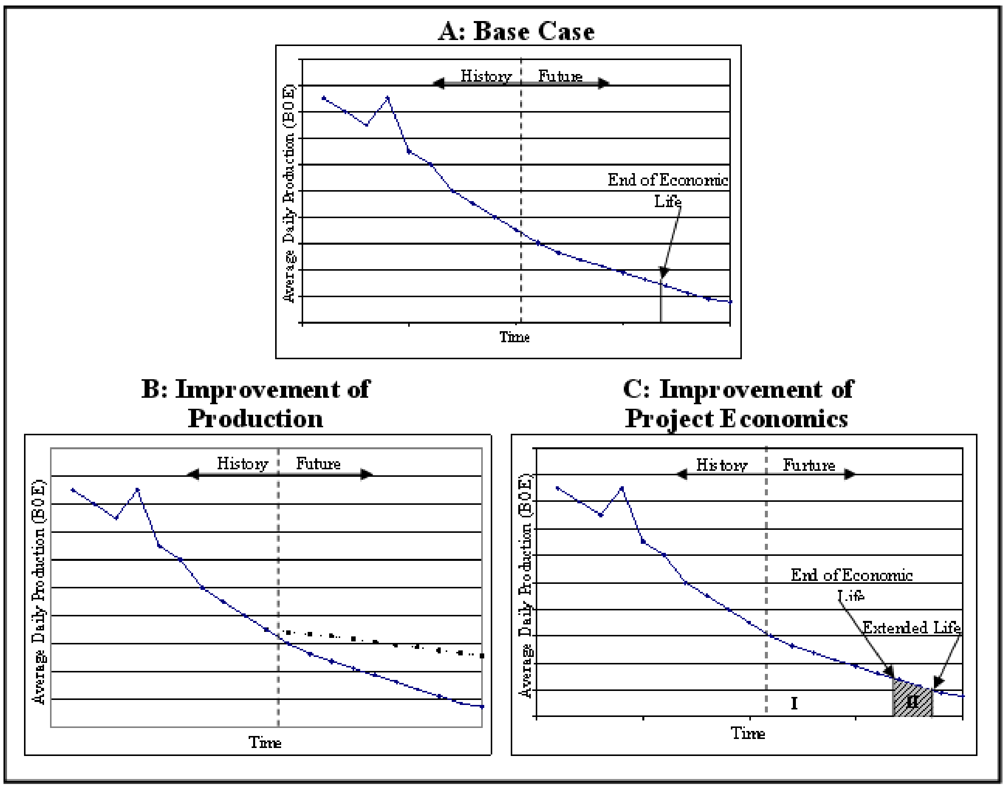
Figure 2-13 illustrates the effects of technology improvement on the production and project economics of a hypothetical well. The graphs plot the daily average production, projected by decline analysis, over the life of the project. Each graph represents a different scenario: (A) base case, (B) production improvement, and (C) economic improvement.

Graph A plots the production for the base case. In the base case, no new technology is applied to the project. The end of the project's economic life, the point at which potential revenues are less than costs of further production, is indicated. At that point, the project would be subject to reserves-growth processes or shut in.

Graph B plots the production for the base case and a production-increasing technology such as skin reduction. The reduction in skin, through well-bore fracturing or acidizing, increases the daily production flow rate. The increase in daily production rate is shown by the dotted line in graph B. The outcome of the production-increasing technology is reserves growth for the well. The amount of reserves growth for the well is shown by the area between the two lines as illustrated in figure 2-13 graph B.

Another example of technology improvement is captured in graph C. In this case a technology is implemented that reduces the cost of operation and maintenance, thereby extending the reservoir life as shown in figure 2-13 graph C.

Figure 2-13: Impact of Economic and Technology Levers

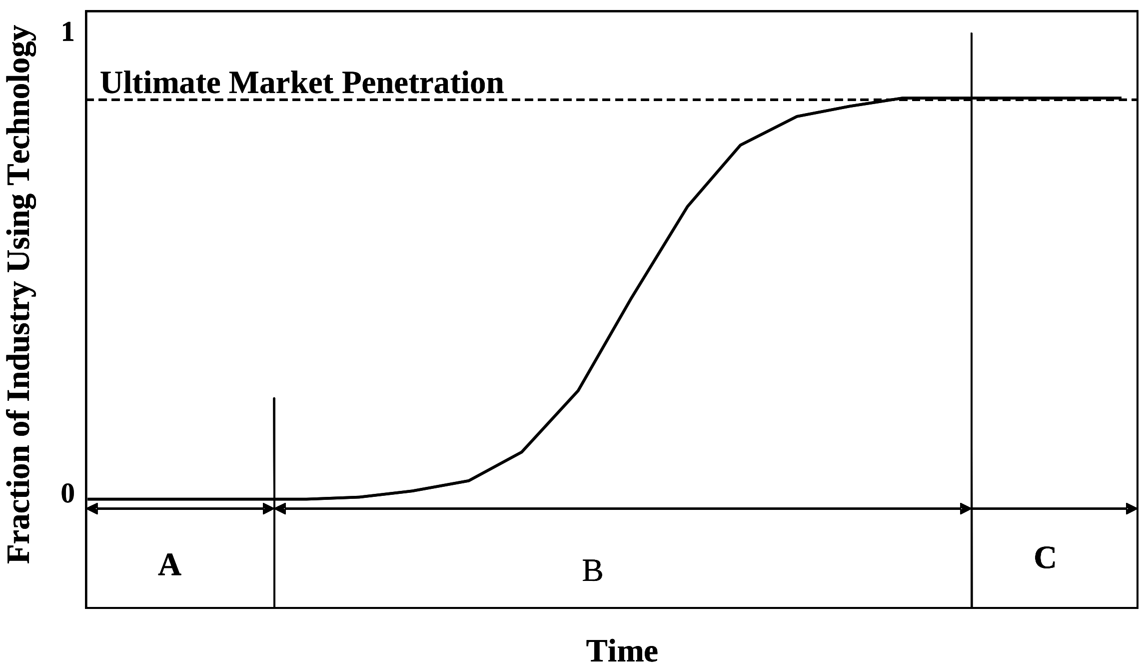


Technology improvements are modeled in OLOGSS using a variety of technology and economic levers. The technology levers, which impact production, are applied to the technical production of the project. The economic levers, which model improvement in project economics, are applied to cashflow calculations. Technology penetration curves are used to model the market penetration of each technology.

The technology-penetration curve is divided into three sections, each of which represents a phase of development. The first section is the research and development phase. In this phase the technology is developed and tested in the laboratory. During these years, the industry may be aware of the technology but has not begun implementation, and therefore does not see a benefit to production or economics. The second section corresponds to the commercialization phase. In the commercialization phase, the technology has successfully left the laboratory and is being adopted by the industry. The third section represents maximum market penetration. This is the ultimate extent to which the technology is adopted by the industry.

Figure 2-14 provides the graph of a generic technology-penetration curve. This graph plots the fraction of industry using the new technology (between 0 and 1) over time. During the research and development phase (A) the fraction of the industry using the technology is 0. This increases during commercialization phase (B) until it reaches the ultimate market penetration. In phase C, the period of maximum market acceptance, the percentage of industry using the technology remains constant.

Figure 2-14: Generic Technology Penetration Curve

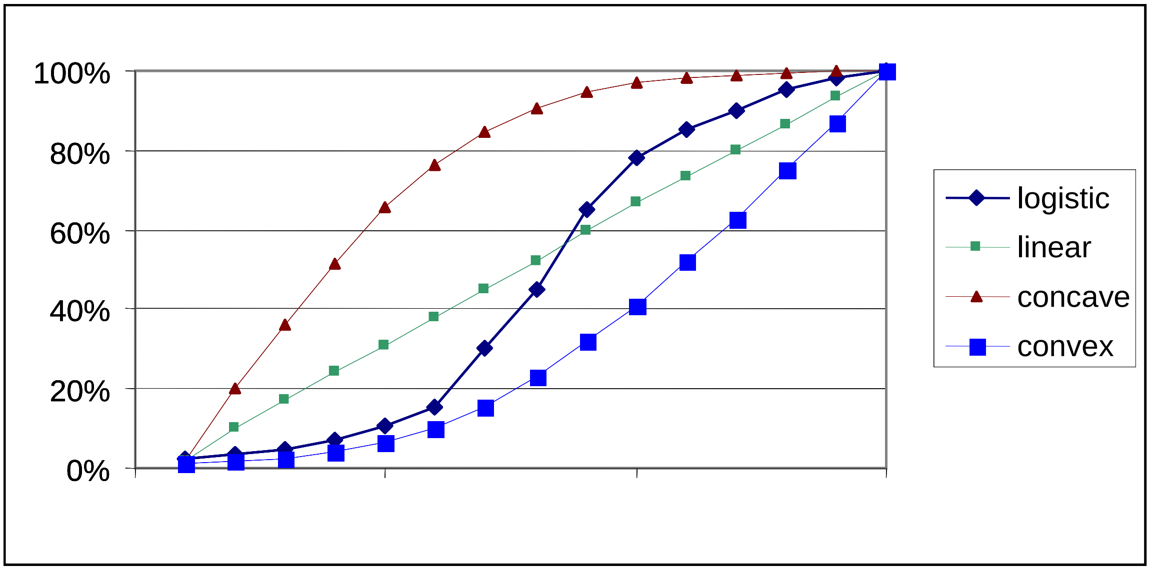


Technology modeling in OLOGSS

The success of the technology program is measured by estimating the probability that the technology development program will be successfully completed. It reflects the pace at which technology performance improves and the probability that the technology project will meet the program goals. There are four possible curve shapes that may represent the adoption of the technology: convex, concave, sigmoid/logistic or linear, as shown in figure 2-15. The convex curve corresponds to rapid initial market penetration followed by slow market penetration. The concave curve corresponds to slow initial market penetration followed by rapid market penetration. The sigmoid/logistic curve represents a slow initial adoption rate followed by rapid increase in adoption and the slow adoption again as the market becomes saturated. The linear curve represents a constant rate of market penetration, and may be used when no other predictions can be made.

The market penetration curve is a function of the relative economic attractiveness of the technology instead of being a time-dependent function. A technology will not be implemented unless the benefits through increased production or cost reductions are greater than the cost to apply the technology. As a result, the market penetration curve provides a limiting value on commercialization instead of a specific penetration path. In addition to the curve, the implementation probability captures the fact that not all technologies that have been proved in the lab are able to be successfully implemented in the field. The implementation probability does not reflect resource access, development constraints, or economic factors.

Figure 2-15: Potential Market Penetration Profiles



The three phases of the technology penetration curve are modeled using three sets of equations. The first set of equations models the research and development phase, the second set models the commercialization phase, and the third set models the maximum market penetration phase.

In summary, technology penetration curves are defined using the following variables:

- Number of years required to develop a technology = Y_d
- First year of commercialization = Y_c
- Number of years to fully penetrate the market = Y_a
- Ultimate market penetration (%) = UP
- Probability of success = P_s
- Probability of implementation = P_i
- Percent of industry implementing the technology (fraction) in year x = Imp_x

Research and Development Phase:
During the research and development phase, the percentage of industry implementing the new technology for a given year is zero.

This equation is used for all values of *market_penetration_profile.*

Commercialization Phase:

The commercialization phase covers the years from the beginning of commercialization through the number of years required to fully develop the technology. The equations used to model this phase depend upon the value of *market_penetration_profile.*

If the *market_penetration_profile* is assumed to be *convex,* then

Step 1: Calculate raw implementation percentage:

$$Imp_{xr} = -0.9 * 0.4^{[(x - Ys) / Ya]} \qquad (2\text{-}105)$$

Step 2: Normalize Imp_x using the following equation:

$$Imp_x = \frac{[(-0.6523) - Imp_x]}{[(-0.6523) - (-0.036)]} \qquad (2\text{-}106)$$

If the *market_penetration_profile* is assumed to be *concave,* then

Step 1: Calculate raw implementation percentage:

$$Imp_x = 0.9 * 0.04^{[1 - \{(x + 1 - Ys)/ Ya\}]} \qquad (2\text{-}107)$$

Step 2: Normalize Imp_x using the following equation:

$$Imp_x = \frac{[(0.04) - Imp_{xr}]}{[(0.04) - (0.74678)]} \qquad (2\text{-}108)$$

If the *market_penetration_profile* is assumed to be *sigmoid,* then

Step 1: Determine midpoint of the sigmoid curve = int $\left(\frac{Y_a}{2}\right)$

Where int$\left(\frac{Y_a}{2}\right)$ = $\left(\frac{Y_a}{2}\right)$ rounded to the nearest integer

Step 2: Assign a value of 0 to the midpoint year of the commercialization period, incrementally increase the values for the years above the midpoint year, and incrementally decrease the values for the years below the midpoint year.

Step 3: Calculate raw implementation percentage:

$$Imp_x = \frac{e^{value_x}}{1 + e^{value_x}} \qquad (2\text{-}109)$$

No normalizing of Imp_x is required for the sigmoid profile.

If the *market_penetration_profile* is assumed to be *linear,* then

Step 1: Calculate the raw implementation percentage:

$$\text{Imp}_x = \left[\frac{P_s * P_i * UP}{Y_a + 1}\right] * x_i \quad (2\text{-}110)$$

No normalizing of Imp_x is required for the linear profile.

Note that the maximum technology penetration is 1.

Ultimate Market Penetration Phase:
For each of the curves generated, the ultimate technology penetration applied per year will be calculated using:

$$\text{Imp}_{final} = \text{Imp}_x * P_s * P_i \quad (2\text{-}111)$$

Note that Imp_{final} is not to exceed Ultimate Market Penetration ("UP")

Using these three sets of equations, the industry-wide implementation of a technology improvement can be mapped using a technology-penetration curve.

Levers included in model

Project Level Technology Impact: Adopting a new technology can impact two aspects of a project. It improves the production and/or improves the economics. Technology and economic levers are variables in OLOGSS. The values for these levers are set by the user.

There are two cost variables to which economic levers can be applied in the cashflow calculations: the cost of applying the technology and the cost reductions that result from the technology's implementation. The cost to apply is the incremental cost to apply the technology. The cost reduction is the savings associated with using the new technology. The "cost to apply" levers can be applied at the well and/or project level. The model recognizes the distinction between technologies that are applied at the well level – modeling while drilling - and reservoir characterization and simulation, which affects the entire project. By using both types of levers, users can model the relationship between implementation costs and offsetting cost reductions.

The model assumes that the technology will be implemented only if the cost to apply the technology is less than the increased revenue generated through improved production and cost reductions.

Resource and Filter Levers: Two other types of levers are incorporated into OLOGSS: resource-access levers and technology levers. Resource-access levers allow the user to model changes in resource-access policy. For example, the user can specify that the federal lands in the Santa Maria Basin, which are currently inaccessible due to statutory or executive orders, will be available for exploration in 2015. A series of filter levers is also incorporated in the model. These are used to specifically locate the impact of technology improvement. For example, a technology can be applied only to CO_2 flooding projects in the Rocky Mountain region that are between 5,000 and 7,000 feet deep.

Appendix 2.A: Onshore Lower 48 Data Inventory

Variable Name	Variable Type	Description	Unit
AAPI	Input	API gravity	
AARP	Input	CO_2 source acceptance rate	
ABO	Variable	Current formation volume factor	Bbl/stb
ABOI	Input	Initial formation volume factor	Bbl/stb
ABTU	Variable	BTU content	Btu/Cf
ACER	Input	ACE rate	Percent
ACHGASPROD	Input	Cumulative historical natural gas production	MMcf
ACHOILPROD	Input	Cumulative historical crude oil production	MBbl
ACO2CONT	Input	CO_2 impurity content	%
ADEPTH	Input	Depth	Feet
ADGGLA	Variable	Depletable items in the year (G & G and lease acquisition cost)	K$
ADJGAS	Variable	National natural gas drilling adjustment factor	Fraction
ADJGROSS	Variable	Adjusted gross revenue	K$
ADJOIL	Variable	National crude oil drilling adjustment factor	Fraction
ADOILPRICE	Variable	Adjusted crude oil price	$/Bbl
ADVANCED	Variable	Patterns to be developed using advanced technology	Fraction
AECON_LIFE	Variable	Economic life of the project	Years
AFLP	Input	Portion of reservoir on federal lands	Fraction
AGAS_GRAV	Input	Natural gas gravity	
AGOR	Input	Gas/oil ratio	Mcf/bbl
AH2SCONT	Input	H_2S impurity content	%
AHCPV	Variable	Hydro Carbon Pore Volume	0.4 HCPV
AHEATVAL	Input	Heat content of natural gas	Btu/Cf
AINJINJ	Input	Annual injectant injected	MBbl, Mcf, MLbs
AINJRECY	Variable	Annual injectant recycled	MBbl, Mcf
AIRSVGAS	Variable	End of year inferred natural gas reserves	MMcf
AIRSVOIL	Variable	End of year inferred crude oil reserves	MBbl
ALATLEN	Input	Lateral length	Feet
ALATNUM	Input	Number of laterals	
ALYRGAS	Input	Last year of historical natural gas production	MMcf

ALYROIL	Input	Last year of historical crude oil production	MBbl
AMINT	Variable	Alternative minimum income tax	K$
AMOR	Variable	Intangible investment depreciation amount	K$
AMOR_BASE	Variable	Amortization base	K$
AMORSCHL	Input	Annual fraction amortized	Fraction
AMT	Input	Alternative minimum tax	K$
AMTRATE	Input	Alternative minimum tax rate	K$
AN2CONT	Input	N_2 impurity content	%
ANGL	Input	NGL	bbl/MMcf
ANUMACC	Input	Number of accumulations	
ANWELLGAS	Input	Number of natural gas wells	
ANWELLINJ	Input	Number of injection wells	
ANWELLOIL	Input	Number of crude oil wells	
AOAM	Variable	Annual fixed O & M cost	K$
AOGIP	Variable	Original Gas in Place	Bcf
AOILVIS	Input	Crude Oil viscosity	CP
AOOIP	Variable	Original Oil In Place	MBbl
AORGOOIP	Input	Original OOIP	MBbl
APATSIZ	Input	Pattern size	Acres
APAY	Input	Net pay	Feet
APD	Variable	Annual percent depletion	K$
APERM	Input	Permeability	MD
APHI	Input	Porosity	Percent
APLAY_CDE	Input	Play number	
APRESIN	Variable	Initial pressure	PSIA
APRODCO2	Input	Annual CO_2 production	MMcf
APRODGAS	Input	Annual natural gas production	MMcf
APRODNGL	Input	Annual NGL production	MBbl
APRODOIL	Input	Annual crude oil production	MBbl
APRODWAT	Input	Annual water production	MBbl
APROV	Input	Province	
AREGION	Input	Region number	
ARESACC	Input	Resource Access	
ARESFLAG	Input	Resource flag	
ARESID	Input	Reservoir ID number	
ARESVGAS	Variable	End of year proven natural gas reserves	MMcf
ARESVOIL	Variable	End of year proven crude oil reserves	MBbl
ARRC	Input	Railroad Commission District	
ASC	Input	Reservoir Size Class	
ASGI	Variable	Gas saturation	Percent
ASOC	Input	Current oil saturation	Percent
ASOI	Input	Initial oil saturation	Percent

ASOR	Input	Residual oil saturation	Percent
ASR_ED	Input	Number of years after economic life of ASR	
ASR_ST	Input	Number of years before economic life of ASR	
ASULFOIL	Input	Sulfur content of crude oil	%
ASWI	Input	Initial water saturation	Percent
ATCF	Variable	After tax cashflow	K$
ATEMP	Variable	Reservoir temperature	F°
ATOTACRES	Input	Total area	Acres
ATOTCONV	Input	Number of conversions from producing wells to injecting wells per pattern	
ATOTINJ	Input	Number of new injectors drilled per pattern	
ATOTPAT	Input	Total number of patterns	
ATOTPROD	Input	Number of new producers drilled per pattern	
ATOTPS	Input	Number of primary wells converted to secondary wells per pattern	
AVDP	Input	Dykstra Parsons coefficient	
AWATINJ	Input	Annual water injected	MBbl
AWOR	Input	Water/oil ratio	Bbl/Bbl
BAS_PLAY	Input	Basin number	
BASEGAS	Input	Base natural gas price used for normalization of capital and operating costs	$/Mcf
BASEOIL	Input	Base crude oil price used for normalization of capital and operating costs	K$
BSE_AVAILCO2	Variable	Base annual volume of CO_2 available by region	Bcf
CAP_BASE	Variable	Capital to be depreciated	K$
CAPMUL	Input	Capital constraints multiplier	
CATCF	Variable	Cumulative discounted cashflow	K$
CHG_ANNSEC_FAC	Input	Change in annual secondary operating cost	Fraction
CHG_CHMPNT_FAC	Input	Change in chemical handling plant cost	Fraction
CHG_CMP_FAC	Input	Change in compression cost	Fraction
CHG_CO2PNT_FAC	Input	Change in CO_2 injection/recycling plant cost	Fraction
CHG_COMP_FAC	Input	Change in completion cost	Fraction
CHG_DRL_FAC	Input	Change in drilling cost	Fraction
CHG_FAC_FAC	Input	Change in facilities cost	Fraction

CHG_FACUPG_FAC	Input	Change in facilities upgrade cost	Fraction
CHG_FOAM_FAC	Input	Change in fixed annual O & M cost	Fraction
CHG_GNA_FAC	Input	Change in G & A cost	Fraction
CHG_INJC_FAC	Input	Change in injection cost	Fraction
CHG_INJCONV_FAC	Input	Change in injector conversion cost	Fraction
CHG_INJT_FAC	Input	Change in injectant cost	Fraction
CHG_LFT_FAC	Input	Change in lifting cost	Fraction
CHG_OGAS_FAC	Input	Change in natural gas O & M cost	K$
CHG_OINJ_FAC	Input	Change in injection O & M cost	K$
CHG_OOIL_FAC	Input	Change in oil O & M cost	K$
CHG_OWAT_FAC	Input	Change in water O & M cost	K$
CHG_PLYPNT_FAC	Input	Change in polymer handling plant cost	Fraction
CHG_PRDWAT_FAC	Input	Change in produced water handling plant cost	Fraction
CHG_SECWRK_FAC	Input	Change in secondary workover cost	Fraction
CHG_SECCONV_FAC	Input	Change in secondary conversion cost	Fraction
CHG_STM_FAC	Input	Change in stimulation cost	Fraction
CHG_STMGEN_FAC	Input	Change in steam generation and distribution cost	Fraction
CHG_VOAM_FAC	Input	Change in variable O & M cost	Fraction
.CHG_WRK_FAC	Input	Change in workover cost	Fraction
CHM_F	Variable	Cost for a chemical handling plant	K$
CHMA	Input	Chemical handling plant	
CHMB	Input	Chemical handling plant	
CHMK	Input	Chemical handling plant	
CIDC	Input	Capitalize intangible drilling costs	K$
CO2_F	Variable	Cost for a CO_2 recycling/injection plant	K$
CO2_RAT_ FAC	Input	CO_2 injection factor	
CO2AVAIL	Variable	Total CO_2 available in a region across all sources	Bcf/Yr
CO2BASE	Input	Total Volume of CO_2 Available	Bcf/Yr
CO2COST	Variable	Final cost for CO_2	$/Mcf

CO2B	Input	Constant and coefficient for natural CO_2 cost equation	
CO2K	Input	Constant and coefficient for natural CO_2 cost equation	
CO2MUL	Input	CO_2 availability constraint multiplier	
CO2OAM	Variable	CO_2 variable O & M cost	K$
CO2OM_20	Input	The O & M cost for CO_2 injection < 20 MMcf	K$
CO2OM20	Input	The O & M cost for CO_2 injection > 20 MMcf	K$
CO2PR	Input	State/regional multipliers for natural CO_2 cost	
CO2PRICE	Input	CO_2 price	$/Mcf
CO2RK, CO2RB	Input	CO_2 recycling plant cost	K$
CO2ST	Input	State code for natural CO_2 cost	
COI	Input	Capitalize other intangibles	
COMP	Variable	Compressor cost	K$
COMP_OAM	Variable	Compressor O & M cost	K$
COMP_VC	Input	Compressor O & M costs	K$
COMP_W	Variable	Compression cost to bring natural gas up to pipeline pressure	K$
COMYEAR_FAC	Input	Number of years of technology commercialization for the penetration curve	Years
CONTIN_ FAC	Input	Continuity increase factor	
COST_BHP	Input	Compressor Cost	$/Bhp
COTYPE	Variable	CO_2 source, either industrial or natural	
CPI_2003	Variable	CPI conversion for 2003$	
CPI_2005	Variable	CPI conversion for 2005$	
CPI_AVG	Input	Average CPI from 1990 to 2010	
CPI_FACTOR	Input	CPI factor from 1990 to 2010	
CPI_YEAR	Input	Year for CPI index	
CREDAMT	Input	Flag that allows AMT to be credited in future years	
CREGPR	Input	The CO_2 price by region and source	$/Mcf
CST_ANNSEC_ FAC	Input	Well level cost to apply secondary producer technology	K$
CST_ANNSEC_CSTP	Variable	Project level cost to apply secondary producer technology	K$

CST_CMP_CSTP	Variable	Project level cost to apply compression technology	K$
CST_CMP_FAC	Input	Well level cost to apply compression technology	K$
CST_COMP_ FAC	Input	Well level cost to apply completion technology	K$
CST_COMP_CSTP	Variable	Project level cost to apply completion technology	K$
CST_DRL_ FAC	Input	Well level cost to apply drilling technology	K$
CST_DRL_CSTP	Variable	Project level cost to apply drilling technology	K$
CST_FAC_ FAC	Input	Well level cost to apply facilities technology	K$
CST_FAC_CSTP	Variable	Project level cost to apply facilities technology	K$
CST_FACUPG_ FAC	Input	Well level cost to apply facilities upgrade technology	K$
CST_FACUPG_CSTP	Variable	Project level cost to apply facilities upgrade technology	K$
CST_FOAM_ FAC	Input	Well level cost to apply fixed annual O & M technology	K$
CST_FOAM_CSTP	Variable	Project level cost to apply fixed annual O & M technology	K$
CST_GNA_ FAC	Input	Well level cost to apply G & A technology	K$
CST_GNA_CSTP	Variable	Project level cost to apply G & A technology	K$
CST_INJC_ FAC	Input	Well level cost to apply injection technology	K$
CST_INJC_CSTP	Variable	Project level cost to apply injection technology	K$
CST_INJCONV_ FAC	Input	Well level cost to apply injector conversion technology	K$
CST_INJCONV_CSTP	Variable	Project level cost to apply injector conversion technology	K$
CST_LFT_ FAC	Input	Well level cost to apply lifting technology	K$
CST_LFT_CSTP	Variable	Project level cost to apply lifting technology	K$
CST_SECCONV_ FAC	Input	Well level cost to apply secondary conversion technology	K$

CST_SECCONV_CSTP	Variable	Project level cost to apply secondary conversion technology	K$
CST_SECWRK_ FAC	Input	Well level cost to apply secondary workover technology	K$
CST_SECWRK_CSTP	Variable	Project level cost to apply secondary workover technology	K$
CST_STM_ FAC	Input	Well level cost to apply stimulation technology	K$
CST_STM_CSTP	Variable	Project level cost to apply stimulation technology	K$
CST_VOAM_ FAC	Input	Well level cost to apply variable annual O & M technology	K$
CST_VOAM_CSTP	Variable	Project level cost to apply variable annual O & M technology	K$
CST_WRK_ FAC	Input	Well level cost to apply workover technology	K$
CST_WRK_CSTP	Variable	Project level cost to apply workover technology	K$
CSTP_ANNSEC_ FAC	Input	Project level cost to apply secondary producer technology	K$
CSTP_CMP_ FAC	Input	Project level cost to apply compression technology	K$
CSTP_COMP_ FAC	Input	Project level cost to apply completion technology	K$
CSTP_DRL_ FAC	Input	Project level cost to apply drilling technology	K$
CSTP_FAC_ FAC	Input	Project level cost to apply facilities technology	K$
CSTP_FACUPG_ FAC	Input	Project level cost to apply facilities upgrade technology	K$
CSTP_FOAM_ FAC	Input	Project level cost to apply fixed annual O & M technology	K$
CSTP_GNA_ FAC	Input	Project level cost to apply G & A technology	K$
CSTP_INJC_ FAC	Input	Project level cost to apply injection technology	K$
CSTP_INJCONV_ FAC	Input	Project level cost to apply injector conversion technology	K$
CSTP_LFT_ FAC	Input	Project level cost to apply lifting technology	K$

CSTP_SECCONV_ FAC	Input	Project level cost to apply secondary conversion technology	K$
CSTP_SECWRK_ FAC	Input	Project level cost to apply secondary workover technology	K$
CSTP_STM_ FAC	Input	Project level cost to apply stimulation technology	K$
CSTP_VOAM_ FAC	Input	Project level cost to apply variable annual O & M technology	K$
CSTP_WRK_ FAC	Input	Project level cost to apply workover technology	K$
CUTOIL	Input	Base crude oil price for the adjustment term of price normalization	$/Bbl
DATCF	Variable	Discounted cashflow after taxes	K$
DEP_CRD	Variable	Depletion credit	K$
DEPLET	Variable	Depletion allowance	K$
DEPR	Variable	Depreciation amount	K$
DEPR_OVR	Input	Annual fraction to depreciate	
DEPR_PROC	Input	Process number for override schedule	
DEPR_YR	Input	Number of years for override schedule	
DEPRSCHL	Input	Annual Fraction Depreciated	Fraction
DEPR_SCH	Variable	Process specific depreciation schedule	Years
DGGLA	Variable	Depletion base (G & G and lease acquisition cost)	K$
DISC_DRL	Variable	Discounted drilling cost	K$
DISC_FED	Variable	Discounted federal tax payments	K$
DISC_GAS	Variable	Discounted revenue from natural gas sales	K$
DISC_INV	Variable	Discounted investment rate	K$
DISC_NDRL	Variable	Discounted project facilities costs	K$
DISC_OAM	Variable	Discounted O & M cost	K$
DISC_OIL	Variable	Discounted revenue from crude oil sales	K$
DISC_ROY	Variable	Discounted royalty	K$
DISC_ST	Variable	Discounted state tax rate	K$
DISCLAG	Input	Number of years between discovery and first production	
DISCOUNT_RT	Input	Process discount rates	Percent

DRCAP_D	Variable	Regional dual use drilling footage for crude oil and natural gas development	Ft
DRCAP_G	Variable	Regional natural gas well drilling footage constraints	Ft
DRCAP_O	Variable	Regional crude oil well drilling footage constraints	Ft
DRILL_FAC	Input	Drilling rate factor	
DRILL_OVER	Input	Drilling constraints available for footage over run	%
DRILL_RES	Input	Development drilling constraints available for transfer between crude oil and natural gas	%
DRILL_TRANS	Input	Drilling constraints transfer between regions	%
DRILLCST	Variable	Drill cost by project	K$
DRILLL48	Variable	Successful well drilling costs	1987$ per well
DRL_CST	Variable	Drilling cost	K$
DRY_CST	Variable	Dryhole drilling cost	K$
DRY_DWCA	Estimated	Dryhole well cost	K$
DRY_DWCB	Estimated	Dryhole well cost	K$
DRY_DWCC	Estimated	Dryhole well cost	K$
DRY_DWCD	Input	Maximum depth range for dry well drilling cost equations	Ft
DRY_DWCK	Estimated	Constant for dryhole drilling cost equation	
DRY_DWCM	Input	Minimum depth range for dry well drilling equations	Ft
DRY_W	Variable	Cost to drill a dry well	K$
DRYCST	Variable	Dryhole cost by project	K$
DRYL48	Variable	Dry well drilling costs	1987$ per well
DRYWELLL48	Variable	Dry Lower 48 onshore wells drilled	Wells
DWC_W	Variable	Cost to drill and complete a crude oil well	K$
EADGGLA	Variable	G&G and lease acquisition cost depletion	K$
EADJGROSS	Variable	Adjusted revenue	K$
EAMINT	Variable	Alternative minimum tax	K$
EAMOR	Variable	Amortization	K$
EAOAM	Variable	Fixed annual operating cost	K$
EATCF	Variable	After tax cash flow	K$
ECAP_BASE	Variable	Depreciable/capitalized base	K$

ECATCF	Variable	Cumulative discounted after tax cashflow	K$
ECO2CODE	Variable	CO_2 source code	
ECO2COST	Variable	CO_2 cost	K$
ECO2INJ	Variable	Economic CO_2 injection	Bcf/Yr
ECO2LIM	Variable	Source specific project life for CO_2 EOR projects	
ECO2POL	Variable	Injected CO_2	MMcf
ECO2RANKVAL	Variable	Source specific ranking value for CO_2 EOR projects	
ECO2RCY	Variable	CO_2 recycled	Bcf/Yr
ECOMP	Variable	Compressor tangible capital	K$
EDATCF	Variable	Discounted after tax cashflow	K$
EDEP_CRD	Variable	Adjustment to depreciation base for federal tax credits	K$
EDEPGGLA	Variable	Depletable G & G/lease cost	K$
EDEPLET	Variable	Depletion	K$
EDEPR	Variable	Depreciation	K$
EDGGLA	Variable	Depletion base	K$
EDRYHOLE	Variable	Number of dryholes drilled	
EEC	Input	Expensed environmental costs	K$
EEGGLA	Variable	Expensed G & G and lease acquisition cost	K$
EEORTCA	Variable	Tax credit addback	K$
EEXIST_ECAP	Variable	Environmental existing capital	K$
EEXIST_EOAM	Variable	Environmental existing O & M costs	K$
EFEDCR	Variable	Federal tax credits	K$
EFEDROY	Variable	Federal royalty	K$
EFEDTAX	Variable	Federal tax	K$
EFOAM	Variable	CO_2 FOAM cost	K$
EGACAP	Variable	G & A capitalized	K$
EGAEXP	Variable	G & A expensed	K$
EGASPRICE2	Variable	Natural gas price used in the economics	K$
EGG	Variable	Expensed G & G cost	K$
EGGLA	Variable	Expensed G & G and lease acquisition cost	K$
EGGLAADD	Variable	G & G/lease addback	K$
EGRAVADJ	Variable	Gravity adjustment	K$
EGREMRES	Variable	Remaining proven natural gas reserves	Bcf
EGROSSREV	Variable	Gross revenues	K$
EIA	Variable	Environmental intangible addback	K$

EICAP	Variable	Environmental intangible capital	
EICAP2	Variable	Environmental intangible capital	
EIGEN	Variable	Number of steam generators	
EIGREMRES	Variable	Remaining inferred natural gas reserves	Bcf
EII	Variable	Intangible investment	K$
EIIDRL	Variable	Intangible investment drilling	K$
EINJCOST	Variable	CO_2/Polymer cost	K$
EINJDR	Variable	New injection wells drilled per year	
EINJWELL	Variable	Active injection wells per year	
EINTADD	Variable	Intangible addback	K$
EINTCAP	Variable	Tangible investment drilling	K$
EINVEFF	Variable	Investment efficiency	
EIREMRES	Variable	Remaining inferred crude oil reserves	MMBbl
EITC	Input	Environmental intangible tax credit	K$
EITCAB	Input	Environmental intangible tax credit rate addback	%
EITCR	Input	Environmental intangible tax credit rate	K$
ELA	Variable	Lease and acquisition cost	K$
ELYRGAS	Variable	Last year of historical natural gas production	MMcf
ELYROIL	Variable	Last year of historical crude oil production	MBbl
ENETREV	Variable	Net revenues	K$
ENEW_ECAP	Variable	Environmental new capital	K$
ENEW_EOAM	Variable	Environmental new O & M costs	K$
ENIAT	Variable	Net income after taxes	K$
ENIBT	Variable	Net income before taxes	K$
ENPV	Variable	Net present value	K$
ENV_FAC	Input	Environmental capital cost multiplier	
ENVOP_FAC	Input	Environmental operating cost multiplier	
ENVSCN	Input	Include environmental costs?	
ENYRSI	Variable	Number of years project is economic	
EOAM	Variable	Variable operating and maintenance	K$

EOCA	Variable	Environmental operating cost addback	K$
EOCTC	Input	Environmental operating cost tax credit	K$
EOCTCAB	Input	Environmental operating cost tax credit rate addback	%
EOCTCR	Input	Environmental operating cost tax credit rate	K$
EOILPRICE2	Variable	Crude oil price used in the economics	K$
EORTC	Input	EOR tax credit	K$
EORTCA	Variable	EOR tax credit addback	K$
EORTCAB	Input	EOR tax credit rate addback	%
EORTCP	Input	EOR tax credit phase out crude oil price	K$
EORTCR	Input	EOR tax credit rate	K$
EORTCRP	Input	EOR tax credit applied by year	%
EOTC	Variable	Other tangible capital	K$
EPROC_OAM	Variable	Natural gas processing cost	K$
EPRODDR	Variable	New production wells drilled per year	
EPRODGAS	Variable	Economic natural gas production	MMcf
EPRODOIL	Variable	Economic crude oil production	MBbl
EPRODWAT	Variable	Economic water production	MBbl
EPRODWELL	Variable	Active producing wells per year	
EREMRES	Variable	Remaining proven crude oil reserves	MMBbl
EROR	Variable	Rate of return	
EROY	Variable	Royalty	K$
ESEV	Variable	Severance tax	K$
ESHUTIN	Variable	New shut in wells drilled per year	
ESTIM	Variable	Stimulation cost	K$
ESTTAX	Variable	State tax	K$
ESUMP	Variable	Number of patterns	
ESURFVOL	Variable	Total volume injected	MMcf/ MBbl/ MLbs
ETAXINC	Variable	Net income before taxes	K$
ETCADD	Variable	Tax credit addbacks taken from NIAT	K$
ETCI	Variable	Federal tax credit	K$
ETCIADJ	Variable	Adjustment for federal tax credit	K$

ETI	Variable	Tangible investments	K$
ETOC	Variable	Total operating cost	K$
ETORECY	Variable	CO_2/Surf/Steam recycling volume	Bcf/MBbl/Yr
ETORECY_CST	Variable	CO_2/Surf/Steam recycling cost	Bcf/MBbl/Yr
ETTC	Input	Environmental tangible tax credit	K$
ETTCAB	Input	Environmental tangible tax credit rate addback	%
ETTCR	Input	Environmental tangible tax credit rate	K$
EWATINJ	Variable	Economic water injected	MBbl
EX_CONRES	Variable	Number of exploration reservoirs	
EX_FCRES	Variable	First exploration reservoir	
EXIST_ECAP	Variable	Existing environmental capital cost	K$
EXIST_EOAM	Variable	Existing environmental O & M cost	K$
EXP_ADJ	Input	Fraction of annual crude oil exploration drilling which is made available	Fraction
EXP_ADJG	Input	Fraction of annual natural gas exploration drilling which is made available	Fraction
EXPA0	Estimated	Crude oil exploration well footage A0	
EXPA1	Estimated	Crude oil exploration well footage A1	
EXPAG0	Input	Natural gas exploration well footage A0	
EXPAG1	Input	Natural gas exploration well footage A1	
EXPATN	Variable	Number of active patterns	
EXPCDRCAP	Variable	Regional conventional exploratory drilling footage constraints	Ft
EXPCDRCAPG	Variable	Regional conventional natural gas exploration drilling footage constraint	Ft
EXPGG	Variable	Expensed G & G cost	K$
EXPL_FRAC	Input	Exploration drilling for conventional crude oil	%
EXPL_FRACG	Input	Exploration drilling for conventional natural gas	%

EXPL_MODEL	Input	Selection of exploration models	
EXPLA	Variable	Expensed lease purchase costs	K$
EXPLR_ FAC	Input	Exploration factor	
EXPLR_CHG	Variable	Change in exploration rate	
EXPLSORTIRES	Variable	Sort pointer for exploration	
EXPMUL	Input	Exploration constraint multiplier	
EXPRDL48	Variable	Expected Production	Oil-MMB Gas-BCF
EXPUDRCAP	Variable	Regional continuous exploratory drilling footage constraints	Ft
EXPUDRCAPG	Variable	Regional continuous natural gas exploratory drilling footage constraints	Ft
FAC_W	Variable	Facilities upgrade cost	K$
FACCOST	Variable	Facilities cost	K$
FACGA	Estimated	Natural gas facilities costs	
FACGB	Estimated	Natural gas facilities costs	
FACGC	Estimated	Natural gas facilities costs	
FACGD	Input	Maximum depth range for natural gas facilities costs	Ft
FACGK	Estimated	Constant for natural gas facilities costs	
FACGM	Input	Minimum depth range for natural gas facilities costs	Ft
FACUPA	Estimated	Facilities upgrade cost	
FACUPB	Estimated	Facilities upgrade cost	
FACUPC	Estimated	Facilities upgrade cost	
FACUPD	Input	Maximum depth range for facilities upgrade cost	Ft
FACUPK	Estimated	Constant for facilities upgrade costs	
FACUPM	Input	Minimum depth range for facilities upgrade cost	Ft
FCO2	Variable	Cost multiplier for natural CO_2	
FEDRATE	Input	Federal income tax rate	Percent
FEDTAX	Variable	Federal tax	K$
FEDTAX_CR	Variable	Federal tax credits	K$
FIRST_ASR	Variable	First year a decline reservoir will be considered for ASR	
FIRST_DEC	Variable	First year a decline reservoir will be considered for EOR	

FIRSTCOM_FAC	Input	First year of commercialization for technology on the penetration curve	
FIT	Variable	Federal income tax	K$
FOAM	Variable	CO_2 fixed O & M cost	K$
FOAMG_1	Variable	Fixed annual operating cost for natural gas 1	K$
FOAMG_2	Variable	Fixed annual operating cost for natural gas 2	K$
FOAMG_W	Variable	Fixed operating cost for natural gas wells	K$
FGASPRICE	Input	Fixed natural gas price	$/MCF
FOILPRICE	Input	Fixed crude oil price	$/BBL
FPLY	Variable	Cost multiplier for polymer	
FPRICE	Input	Selection to use fixed prices	
FR1L48	Variable	Finding rates for new field wildcat drilling	Oil-MMB per well Gas-BCF per well
FR2L48	Variable	Finding rates for other exploratory drilling	Oil-MMB per well Gas-BCF per well
FR3L48	Variable	Finding rates for developmental drilling	Oil-MMB per well Gas-BCF per well
FRAC_CO2	Variable	Fraction of CO_2	Fraction
FRAC_H2S	Variable	Fraction of hydrogen sulfide	Fraction
FRAC_N2	Variable	Fraction of nitrogen	Fraction
FRAC_NGL	Variable	NGL yield	Fraction
FWC_W	Variable	Natural gas facilities costs	K$
GA_CAP	Variable	G & A on capital	K$
GA_EXP	Variable	G & A on expenses	K$
GAS_ADJ	Input	Fraction of annual natural gas drilling which is made available	Fraction
GAS_CASE	Input	Filter for all natural gas processes	
GAS_DWCA	Estimated	Horizontal natural gas drilling and completion costs	
GAS_DWCB	Estimated	Horizontal natural gas drilling and completion costs	
GAS_DWCC	Estimated	Horizontal natural gas drilling and completion costs	

GAS_DWCD	Input	Maximum depth range for natural gas well drilling cost equations	Ft
GAS_DWCK	Estimated	Constant for natural gas well drilling cost equations	
GAS_DWCM	Input	Minimum depth range for natural gas well drilling cost equations	Ft
GAS_FILTER	Input	Filter for all natural gas processes	
GAS_OAM	Input	Process specific operating cost for natural gas production	$/Mcf
GAS_SALES	Input	Will produced natural gas be sold?	
GASA0	Estimated	Natural gas footage A0	
GASA1	Estimated	Natural gas footage A1	
GASD0	Input	Natural gas drywell footage A0	
GASD1	Input	Natural gas drywell footage A1	
GASPRICE2	Variable	Natural gas price dummy to shift price track	K$
GASPRICEC	Variable	Annual natural gas prices used by cashflow	K$
GASPRICED	Variable	Annual natural gas prices used in the drilling constraints	K$
GASPRICEO	Variable	Annual natural gas prices used by the model	K$
GASPROD	Variable	Annual natural gas production	MMcf
GG	Variable	G & G cost	K$
GG_FAC	Input	G & G factor	
GGCTC	Input	G & G tangible depleted tax credit	K$
GGCTCAB	Input	G & G tangible tax credit rate addback	%
GGCTCR	Input	G & G tangible depleted tax credit rate	K$
GGETC	Input	G & G intangible depleted tax credit	K$
GGETCAB	Input	G & G intangible tax credit rate addback	%
GGETCR	Input	G & G intangible depleted tax credit rate	K$
GGLA	Variable	G & G and lease acquisition addback	K$
GMULT_INT	Input	Natural gas price adjustment factor, intangible costs	K$

GMULT_OAM	Input	Natural gas price adjustment factor, O & M	K$
GMULT_TANG	Input	Natural gas price adjustment factor, tangible costs	K$
GNA_CAP2	Input	G & A capital multiplier	Fraction
GNA_EXP2	Input	G & A expense multiplier	Fraction
GPROD	Variable	Well level natural gas production	MMcf
GRAVPEN	Variable	Gravity penalty	K$
GREMRES	Variable	Remaining proven natural gas reserves	MMcf
GROSS_REV	Variable	Gross revenue	K$
H_GROWTH	Input	Horizontal growth rate	Percent
H_PERCENT	Input	Crude oil constraint available for horizontal drilling	%
H_SUCCESS	Input	Horizontal development well success rate by region	%
H2SPRICE	Input	H_2S price	$/Metric ton
HOR_ADJ	Input	Fraction of annual horizontal drilling which is made available	Fraction
HOR_VERT	Input	Split between horizontal and vertical drilling	
HORMUL	Input	Horizontal drilling constraint multiplier	
IAMORYR	Input	Number of years in default amortization schedule	
ICAP	Variable	Other intangible costs	K$
ICST	Variable	Intangible cost	K$
IDCA	Variable	Intangible drilling capital addback	K$
IDCTC	Input	Intangible drilling cost tax credit	K$
IDCTCAB	Input	Intangible drilling cost tax credit rate addback	%
IDCTCR	Input	Intangible drilling cost tax credit rate	K$
IDEPRYR	Input	Number of years in default depreciation schedule	
IGREMRES	Variable	Remaining inferred natural gas reserves	MMcf
II_DRL	Variable	Intangible drilling cost	K$
IINFARSV	Variable	Initial inferred AD gas reserves	Bcf
IINFRESV	Variable	Initial inferred reserves	MMBbl
IMP_CAPCR	Input	Capacity for NGL cryogenic expander plant	MMCf/D

IMP_CAPST	Input	Capacity for NGL straight refrigeration	MMCf/D
IMP_CAPSU	Input	Capacity for Claus Sulfur Recovery	Long ton/day
IMP_CAPTE	Input	Natural gas processing plant capacity	MMcf/D
IMP_CO2_LIM	Input	Limit on CO_2 in natural gas	Fraction
IMP_DIS_RATE	Input	Discount rate for natural gas processing plant	
IMP_H2O_LIM	Input	Limit on H_2O in natural gas	Fraction
IMP_H2S_LIM	Input	Limit on H_2S in natural gas	Fraction
IMP_N2_LIM	Input	Limit on N^2 in natural gas	Fraction
IMP_NGL_LIM	Input	Limit on NGL in natural gas	Fraction
IMP_OP_FAC	Input	Natural gas processing operating factor	
IMP_PLT_LFE	Input	Natural gas processing plant life	Years
IMP_THRU	Input	Throughput	
IND_SRCCO2	Input	Use industrial source of CO_2?	
INDUSTRIAL	Variable	Natural or industrial CO_2 source	
INFLFAC	Input	Annual Inflation Factor	
INFR_ADG	Input	Adjustment factor for inferred AD gas reserves	Tcf
INFR_CBM	Input	Adjustment factor for inferred coalbed methane reserves	Tcf
INFR_DNAG	Input	Adjustment factor for inferred deep non-associated gas reserves	Tcf
INFR_OIL	Input	Adjustment factor for inferred crude oil reserves	Bbl?
INFR_SHL	Input	Adjustment factor for inferred shale gas reserves	Tcf
INFR_SNAG	Input	Adjustment factor for inferred shallow non-associated gas reserves	Tcf
INFR_THT	Input	Adjustment factor for inferred tight gas reserves	Tcf
INFARSV	Variable	Inferred AD gas reserves	Bcf
INFRESV	Variable	Inferred reserves, crude oil or natural gas	MMBbl, Bcf
INJ	Variable	Injectant cost	K$
INJ_OAM	Input	Process specific operating cost for injection	$/Bbl
INJ_RATE_FAC	Input	Injection rate increase	fraction
INTADD	Variable	Total intangible addback	K$
INTANG_M	Variable	Intangible cost multiplier	

INTCAP	Variable	Intangible to be capitalized	K$
INVCAP	Variable	Annual total capital investments constraints, used for constraining projects	MM$
IPDR	Input	Independent producer depletion rate	
IRA	Input	Max alternate minimum tax reduction for independents	K$
IREMRES	Variable	Remaining inferred crude oil reserves	MBbl
IUNDARES	Variable	Initial undiscovered resource	MMBbl/Tcf
IUNDRES	Variable	Initial undiscovered resource	MMBbl/Tcf
L48B4YR	Input	First year of analysis	
LA	Variable	Lease and acquisition cost	K$
LACTC	Input	Lease acquisition tangible depleted tax credit	K$
LACTCAB	Input	Lease acquisition tangible credit rate addback	%
LACTCR	Input	Lease acquisition tangible depleted tax credit rate	K$
LAETC	Input	Lease acquisition intangible expensed tax credit	K$
LAETCAB	Input	Lease acquisition intangible tax credit rate addback	%
LAETCR	Input	Lease acquisition intangible expensed tax credit rate	K$
LAST_ASR	Variable	Last year a decline reservoir will be considered for ASR	
LAST_DEC	Variable	Last year a decline reservoir will be considered for EOR	
LBC_FRAC	Input	Lease bonus fraction	Fraction
LEASCST	Variable	Lease cost by project	K$
LEASL48	Variable	Lease equipment costs	1987$/well
MARK_PEN_FAC	Input	Ultimate market penetration	
MAXWELL	Input	Maximum number of dryholes per play per year	
MAX_API_CASE	Input	Maximum API gravity	
MAX_DEPTH_CASE	Input	Maximum depth	
MAX_PERM_CASE	Input	Maximum permeability	
MAX_RATE_CASE	Input	Maximum production rate	
MIN_API_CASE	Input	Minimum API gravity	
MIN_DEPTH_CASE	Input	Minimum depth	
MIN_PERM_CASE	Input	Minimum permeability	
MIN_RATE_CASE	Input	Minimum production rate	
MOB_RAT_ FAC	Input	Change in mobility ratio	
MPRD	Input	Maximum depth range for new producer equations	Ft

N_CPI	Input	Number of years	
N2PRICE	Input	N_2 price	$/Mcf
NAT_AVAILCO2	Input	Annual CO_2 availability by region	Bcf
NAT_DMDGAS	Variable	Annual natural gas demand in region	Bcf/Yr
NAT_DRCAP_D	Variable	National dual use drilling footage for crude oil and natural gas development	Ft
NAT_DRCAP_G	Variable	National natural gas well drilling footage constraints	Ft
NAT_DRCAP_O	Variable	National crude oil well drilling footage constraints	Ft
NAT_DUAL	Variable	National dual use drilling footage for crude oil and natural gas development	Ft
NAT_EXP	Variable	National exploratory drilling constraint	Bcf/Yr
NAT_EXPC	Variable	National conventional exploratory drilling crude oil constraint	MBbl/Yr
NAT_EXPCDRCAP	Variable	National conventional exploratory drilling footage constraints	Ft
NAT_EXPCDRCAPG	Variable	National high-permeability natural gas exploratory drilling footage constraints	Ft
NAT_EXPCG	Variable	National conventional exploratory drilling natural gas constraint	Bcf/Yr
NAT_EXPG	Variable	National natural gas exploration drilling constraint	Bcf/Yr
NAT_EXPU	Variable	National continuous exploratory drilling crude oil constraint	MBbl/Yr
NAT_EXPUDRCAP	Variable	National continuous exploratory drilling footage constraints	Ft
NAT_EXPUDRCAPG	Variable	National continuous natural gas exploratory drilling footage constraints	Ft
NAT_EXPUG	Variable	National continuous exploratory drilling natural gas constraint	Bcf/Yr
NAT_GAS	Variable	National natural gas drilling constraint	Bcf/Yr
NAT_GDR	Variable	National natural gas dry drilling footage	Bcf/Yr

NAT_HGAS	Variable	Annual dry natural gas	MMcf
NAT_HOIL	Variable	Annual crude oil and lease condensates	MBbl
NAT_HOR	Variable	Horizontal drilling constraint	MBbl/Yr
NAT_INVCAP	Input	Annual total capital investment constraint	MM$
NAT_ODR	Variable	National crude oil dry drilling footage	MBbl/Yr
NAT_OIL	Variable	National crude oil drilling constraint	MBbl/Yr
NAT_SRCCO2	Input	Use natural source of CO_2?	
NAT_TOT	Variable	Total national footage	Ft
NET_REV	Variable	Net revenue	K$
NEW_ECAP	Variable	New environmental capital cost	K$
NEW_EOAM	Variable	New environmental O & M cost	K$
NEW_NRES	Variable	New total number of reservoirs	
NGLPRICE	Input	NGL price	$/Gal
NGLPROD	Variable	Annual NGL production	MBbl
NIAT	Variable	Net income after taxes	K$
NIBT	Variable	Net income before taxes	K$
NIBTA	Variable	Net operating income after adjustments before addback	K$
NIL	Input	Net income limitations	K$
NILB	Variable	Net income depletable base	K$
NILL	Input	Net income limitation limit	K$
NOI	Variable	Net operating income	K$
NOM_YEAR	Input	Year for nominal dollars	
NPR_W	Variable	Cost to equip a new producer	K$
NPRA	Estimated	Constant for new producer equipment	
NPRB	Estimated	Constant for new producer equipment	
NPRC	Estimated	Constant for new producer equipment	
NPRK	Estimated	Constant for new producer equipment	
NPRM	Input	Minimum depth range for new producer equations	Ft
NPROD	Variable	Well level NGL production	MMcf
NRDL48	Variable	Proved reserves added by new field discoveries	Oil-MMB Gas-BCF
NREG	Input	Number of regions	

NSHUT	Input	Number of years after economics life in which EOR can be considered	
NTECH	Input	Number of technology impacts	
NUMPACK	Input	Number of packages per play per year	
NWELL	Input	Number of wells in continuous exploration drilling package	
OAM	Variable	Variable O & M cost	K$
OAM_COMP	Variable	Compression O & M	K$
OAM_M	Variable	O & M cost multiplier	
OIA	Variable	Other intangible capital addback	K$
OIL_ADJ	Input	Fraction of annual crude oil drilling which is made available	Fraction
OIL_CASE	Input	Filter for all crude oil processes	
OIL_DWCA	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCB	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCC	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCD	Input	Maximum depth range for crude oil well drilling cost equations	Ft
OIL_DWCK	Estimated	Constant for crude oil well drilling cost equations	
OIL_DWCM	Input	Minimum depth range for crude oil well drilling cost equations	Ft
OIL_FILTER	Input	Filter for all crude oil processes	
OIL_OAM	Input	Process specific operating cost for crude oil production	$/Bbl
OIL_RAT_ FAC	Input	Change in crude oil production rate	
OIL_RAT_CHG	Variable	Change in crude oil production rate	
OIL_SALES	Input	Sell crude oil produced from the reservoir?	
OILA0	Estimated	Oil footage A0	
OILA1	Estimated	Oil footage A1	

OILCO2	Input	Fixed crude oil price used for economic pre-screening of industrial CO_2 projects	K$
OILD0	Input	Crude oil drywell footage A0	
OILD1	Input	Crude oil drywell footage A1	
OILPRICEC	Variable	Annual crude oil prices used by cashflow	K$
OILPRICED	Variable	Annual crude oil prices used in the drilling constraints	K$
OILPRICEO	Variable	Annual crude oil prices used by the model	K$
OILPROD	Variable	Annual crude oil production	MBbl
OINJ	Variable	Well level injection	MMcf
OITC	Input	Other intangible tax credit	K$
OITCAB	Input	Other intangible tax credit rate addback	%
OITCR	Input	Other intangible tax credit rate	K$
OMGA	Estimated	Fixed annual cost for natural gas	$/Well
OMGB	Estimated	Fixed annual cost for natural gas	$/Well
OMGC	Estimated	Fixed annual cost for natural gas	$/Well
OMGD	Input	Maximum depth range for fixed annual O & M natural gas cost	Ft
OMGK	Estimated	Constant for fixed annual O & M cost for natural gas	
OMGM	Input	Minimum depth range for fixed annual O & M cost for natural gas	Ft
OML_W	Variable	Variable annual operating cost for lifting	K$
OMLA	Estimated	Lifting cost	$/Well
OMLB	Estimated	Lifting cost	$/Well
OMLC	Estimated	Lifting cost	$/Well
OMLD	Input	Maximum depth range for fixed annual operating cost for crude oil	Ft
OMLK	Estimated	Constant for fixed annual operating cost for crude oil	
OMLM	Input	Minimum depth range for annual operating cost for crude oil	Ft
OMO_W	Variable	Fixed annual operating cost for crude oil	K$

OMOA	Estimated	Fixed annual cost for crude oil	$/Well
OMOB	Estimated	Fixed annual cost for crude oil	$/Well
OMOC	Estimated	Fixed annual cost for crude oil	$/Well
OMOD	Input	Maximum depth range for fixed annual operating cost for crude oil	Ft
OMOK	Estimated	Constant for fixed annual operating cost for crude oil	
OMOM	Input	Minimum depth range for fixed annual operating cost for crude oil	Ft
OMSWRA	Estimated	Secondary workover cost	$/Well
OMSWRB	Estimated	Secondary workover cost	$/Well
OMSWRC	Estimated	Secondary workover cost	$/Well
OMSWRD	Input	Maximum depth range for variable operating cost for secondary workover	Ft
OMSWRK	Estimated	Constant for variable operating cost for secondary workover	
OMSWRM	Input	Minimum depth range for variable operating cost for secondary workover	Ft
OMULT_INT	Input	Crude oil price adjustment factor, intangible costs	
OMULT_OAM	Input	Crude oil price adjustment factor, O & M	
OMULT_TANG	Input	Crude oil price adjustment factor, tangible costs	
OPCOST	Variable	AOAM by project	K$
OPERL48	Variable	Operating Costs	1987$/Well
OPINJ_W	Variable	Variable annual operating cost for injection	K$
OPINJA	Input	Injection cost	$/Well
OPINJB	Input	Injection cost	$/Well
OPINJC	Input	Injection cost	$/Well
OPINJD	Input	Maximum depth range for variable annual operating cost for injection	Ft
OPINJK	Input	Constant for variable annual operating cost for injection	
OPINJM	Input	Minimum depth range for variable annual operating cost for injection	Ft

OPROD	Variable	Well level crude oil production	MBbl
OPSEC_W	Variable	Fixed annual operating cost for secondary operations	K$
OPSECA	Estimated	Annual cost for secondary production	$/Well
OPSECB	Estimated	Annual cost for secondary production	$/Well
OPSECC	Estimated	Annual cost for secondary production	$/Well
OPSECD	Input	Maximum depth range for fixed annual operating cost for secondary operations	Ft
OPSECK	Estimated	Constant for fixed annual operating cost for secondary operations	
OPSECM	Input	Minimum depth range for fixed annual operating cost for secondary operations	Ft
OPT_RPT	Input	Report printing options	
ORECY	Variable	Well level recycled injectant	MBbl
OTC	Variable	Other tangible costs	K$
PATT_DEV	Input	Pattern development	
PATT_DEV_MAX	Input	Maximum pattern development schedule	
PATT_DEV_MIN	Input	Minimum pattern development schedule	
PATDEV	Variable	Annual number of patterns developed for base and advanced technology	
PATN	Variable	Patterns initiated each year	
PATNDCF	Variable	DCF by project	K$
PATTERNS	Variable	Shifted patterns initiated	
PAYCONT_ FAC	Input	Pay continuity factor	
PDR	Input	Percent depletion rate	%
PGGC	Input	Percent of G & G depleted	%
PIIC	Input	Intangible investment to capitalize	%
PLAC	Input	Percent of lease acquisition cost capitalized	%
PLAYNUM	Input	Play number	
PLY_F	Variable	Cost for a polymer handling plant	K$
PLYPA	Input	Polymer handling plant constant	
PLYPK	Input	Polymer handling plant constant	

POLY	Input	Polymer cost	
POLYCOST	Variable	Polymer cost	$/Lb
POTENTIAL	Variable	The number of reservoirs in the resource file	
PRICEYR	Input	First year of prices in price track	K$
PRO_REGEXP	Input	Regional exploration well drilling footage constraint	Ft
PRO_REGEXPG	Input	Regional exploration well drilling footage constraint	Ft
PRO_REGGAS	Input	Regional natural gas well drilling footage constraint	Ft
PRO_REGOIL	Input	Regional crude oil well drilling footage constraint	Ft
PROB_IMP_FAC	Input	Probability of industrial implementation	
PROB_RD_FAC	Input	Probability of successful R & D	
PROC_CST	Variable	Processing cost	$/Mcf
PROC_OAM	Variable	Processing and treating cost	K$
PROCESS_CASE	Input	Filter for crude oil and natural gas processes	
PROCESS_FILTER	Input	Filter for crude oil and natural gas processes	
PROD_IND_ FAC	Input	Production impact	
PROVACC	Input	Year file for resource access	
PROVNUM	Input	Province number	
PRRATL48	Variable	Production to reserves ratio	Fraction
PSHUT	Input	Number of years prior to economic life in which EOR can be considered	
PSI_W	Variable	Cost to convert a primary well to an injection well	K$
PSIA	Estimated	Cost to convert a producer to an injector	
PSIB	Estimated	Cost to convert a producer to an injector	
PSIC	Estimated	Cost to convert a producer to an injector	
PSID	Input	Maximum depth range for producer to injector	Ft
PSIK	Estimated	Constant for producer to injector	
PSIM	Input	Minimum depth range for producer to injector	Ft
PSW_W	Variable	Cost to convert a primary to secondary well	K$

PSWA	Estimated	Cost to convert a primary to secondary well	
PSWB	Estimated	Cost to convert a primary to secondary well	
PSWC	Estimated	Cost to convert a primary to secondary well	
PSWD	Input	Maximum depth range for producer to injector	Ft
PSWK	Estimated	Constant for primary to secondary	
PSWM	Input	Minimum depth range for producer to injector	Ft
PWHP	Input	Produced water handling plant multiplier	K$
PWP_F	Variable	Cost for a produced water handling plant	K$
RDEPTH	Variable	Reservoir depth	ft
RDR	Input	Depth interval	
RDR_FOOTAGE	Variable	Footage available in this interval	Ft
RDR_FT	Variable	Running total of footage used in this bin	Ft
REC_EFF_ FAC	Input	Recovery efficiency factor	
RECY_OIL	Input	Produced water recycling cost	K$
RECY_WAT	Input	Produced water recycling cost	
REG_DUAL	Variable	Regional dual use drilling footage for crude oil and natural gas development	Ft
REG_EXP	Variable	Regional exploratory drilling constraints	MBbl/Yr
REG_EXPC	Variable	Regional conventional crude oil exploratory drilling constraint	MBbl/Yr
REG_EXPCG	Variable	Regional conventional natural gas exploratory drilling constraint	Bcf/Yr
REG_EXPG	Variable	Regional exploratory natural gas drilling constraint	Bcf/Yr
REG_EXPU	Variable	Regional continuous crude oil exploratory drilling constraint	MBbl/Yr
REG_EXPUG	Variable	Regional continuous natural gas exploratory drilling constraint	Bcf/Yr
REG_GAS	Variable	Regional natural gas drilling constraint	Bcf/Yr
REG_HADG	Variable	Regional historical AD gas	MMcf
REG_HCBM	Variable	Regional historical CBM	MMcf

REG_HCNV	Variable	Regional historical high-permeability natural gas	MMcf
REG_HEOIL	Variable	Regional crude oil and lease condensates for continuing EOR	MBbl
REG_HGAS	Variable	Regional dry natural gas	MMcf
REG_HOIL	Variable	Regional crude oil and lease condensates	MBbl
REG_HSHL	Variable	Regional historical shale gas	MMcf
REG_HTHT	Variable	Regional historical tight gas	MMcf
REG_NAT	Input	Regional or national	
REG_OIL	Variable	Regional crude oil drilling constraint	MBbl/Yr
REGDRY	Variable	Regional dryhole rate	
REGDRYE	Variable	Exploration regional dryhole rate	
REGDRYG	Variable	Development natural gas regional dryhole rate	
REGDRYKD	Variable	Regional dryhole rate for discovered development	
REGDRYUD	Variable	Regional dryhole rate for undiscovered development	
REGDRYUE	Variable	Regional dryhole rate for undiscovered exploration	
REGION_CASE	Input	Filter for OLOGSS region	
REGION_FILTER	Input	Filter for OLOGSS region	
REGSCALE_CBM	Input	Regional historical daily CBM gas production for the last year of history	Bcf
REGSCALE_CNV	Input	Regional historical daily high-permeability natural gas production for the last year of history	Bcf
REGSCALE_GAS	Input	Regional historical daily natural gas production for the last year of history	Bcf
REGSCALE_OIL	Input	Regional historical daily crude oil production for the last year of history	MBbl
REGSCALE_SHL	Input	Regional historical daily shale gas production for the last year of history	Bcf
REGSCALE_THT	Input	Regional historical daily tight gas production for the last year of history	Bcf
REM_AMOR	Variable	Remaining amortization base	K$
REM_BASE	Variable	Remaining depreciation base	K$

REMRES	Variable	Remaining proven crude oil reserves	MBbl
RESADL48	Variable	Total additions to proved reserves	Oil-MMB Gas-BCF
RESBOYL48	Variable	End of year reserves for current year	Oil-MMB Gas-BCF
RES_CHR_ FAC	Input	Reservoir characterization cost	$/Cumulative BOE
RES_CHR_CHG	Variable	Reservoir characterization cost	$/Cumulative BOE
RESV_ADGAS	Input	Historical AD gas reserves	Tcf
RESV_CBM	Input	Historical coalbed methane reserves	Tcf
RESV_CONVGAS	Input	Historical high-permeability dry natural gas reserves	Tcf
RESV_OIL	Input	Historical crude oil and lease condensate reserves	BBbl
RESV_SHL	Input	Historical shale gas reserves	Tcf
RESV_THT	Input	Historical tight gas reserves	Tcf
RGR	Input	Annual drilling growth rate	
RIGSL48	Variable	Available rigs	Rigs
RNKVAL	Input	Ranking criteria for the projects	
ROR	Variable	Rate of return	K$
ROYALTY	Variable	Royalty	K$
RREG	Variable	Reservoir region	
RRR	Input	Annual drilling retirement rate	
RUNTYPE	Input	Resources selected to evaluate in the Timing subroutine	
RVALUE	Variable	Reservoir technical crude oil production	MBbl
SCALE_DAY	Input	Number of days in the last year of history	Days
SCALE_GAS	Input	Historical daily natural gas production for the last year of history	Bcf
SCALE_OIL	Input	Historical daily crude oil production for the last year of history	MBbl
SEV_PROC	Variable	Process code	
SEV_TAX	Variable	Severance tax	K$
SFIT	Variable	Alternative minimum tax	K$
SKIN_FAC	Input	Skin factor	
SKIN_CHG	Variable	Change in skin amount	
SMAR	Input	Six month amortization rate	%

SPLIT_ED	Input	Split exploration and development	
SPLIT_OG	Input	Split crude oil and natural gas constraints	
STARTPR	Variable	First year a pattern is initiated	
STATE_TAX	Variable	State tax	K$
STIM	Variable	Stimulation cost	K$
STIM_A, STIM_B	Input	Coefficients for natural gas/oil stimulation cost	K$
STIM_W	Variable	Natural gas well stimulation cost	K$
STIM_YR	Input	Number of years between stimulations of natural gas/oil wells	
STIMFAC	Input	Stimulation efficiency factor	
STL	Variable	State identification number	
STMGA	Input	Steam generator cost multiplier	
STMM_F	Variable	Cost for steam manifolds and generators	K$
STMMA	Input	Steam manifold/pipeline multiplier	
SUCCHDEV	Variable	Horizontal development well success rate by region	Fraction
SUCDEVE	Input	Developmental well dryhole rate by region	%
SUCDEVG	Variable	Final developmental natural gas well success rate by region	Fraction
SUCDEVO	Variable	Final developmental crude oil well success rate by region	Fraction
SUCEXP	Input	Undiscovered exploration well dryhole rate by region	%
SUCEXPD	Input	Exploratory well dryhole rate by region	%
SUCG	Variable	Initial developmental natural gas well success rate by region	Fraction
SUCO	Variable	Initial developmental crude oil well success by region	Fraction
SUCWELLL48	Variable	Successful Lower 48 onshore wells drilled	Wells
SUM_DRY	Variable	Developmental dryholes drilled	
SUM_GAS_CONV	Variable	High-permeability natural gas drilling	MMcf

SUM_GAS_UNCONV	Variable	Low-permeability natural gas drilling	MMcf
SUM_OIL_CONV	Variable	Conventional crude oil drilling	MBbl
SUM_OIL_UNCONV	Variable	Continuous crude oil drilling	MBbl
SUMP	Variable	Total cumulative patterns	
SWK_W	Variable	Secondary workover cost	K$
TANG_FAC_RATE	Input	Percentage of the well costs which are tangible	Percent
TANG_M	Variable	Tangible cost multiplier	
TANG_RATE	Input	Percentage of drilling costs which are tangible	Percent
TCI	Variable	Total capital investments	K$
TCIADJ	Variable	Adjusted capital investments	K$
TCOII	Input	Tax credit on intangible investments	K$
TCOTI	Input	Tax credit on tangible investments	K$
TDTC	Input	Tangible development tax credit	K$
TDTCAB	Input	Tangible development tax credit rate addback	%
TDTCR	Input	Tangible development tax credit rate	K$
TECH01_FAC	Input	WAG ratio applied to CO2EOR	
TECH02_FAC	Input	Recovery Limit	
TECH03_FAC	Input	Vertical Skin Factor for natural gas	
TECH04_FAC	Input	Fracture Half Length	Ft
TECH05_FAC	Input	Fracture Conductivity	Ft
TECH_CO2FLD	Variable	Technical production from CO_2 flood	MBbl
TECH_COAL	Variable	Annual technical coalbed methane gas production	MMcf
TECH_CURVE	Variable	Technology commercialization curve for market penetration	
TECH_CURVE_FAC	Input	Technology commercialization curve for market penetration	
TECH_DECLINE	Variable	Technical decline production	MBbl
TECH_GAS	Variable	Annual technical natural gas production	MMcf
TECH_HORCON	Variable	Technical production from horizontal continuity	MBbl

TECH_HORPRF	Variable	Technical production for horizontal profile	MBbl
TECH_INFILL	Variable	Technical production from infill drilling	MBbl
TECH_NGL	Variable	Annual technical NGL production	MBbl
TECH_OIL	Variable	Annual technical crude oil production	MBbl
TECH_PLYFLD	Variable	Technical production from polymer injection	MBbl
TECH_PRFMOD	Variable	Technical production from profile modification	MBbl
TECH_PRIMARY	Variable	Technical production from primary sources	MBbl
TECH_RADIAL	Variable	Technical production from conventional radial flow	MMcf
TECH_SHALE	Variable	Annual technical shale gas production	MMcf
TECH_STMFLD	Variable	Technical production from steam flood	MBbl
TECH_TIGHT	Variable	Annual technical tight gas production	MMcf
TECH_TIGHTG	Variable	Technical tight gas production	MMcf
TECH_UCOALB	Variable	Technical undiscovered coalbed methane production	MMcf
TECH_UCONTO	Variable	Technical undiscovered continuous crude oil production	MBbl
TECH_UCONVG	Variable	Technical low-permeability natural gas production	MMcf
TECH_UCONVO	Variable	Technical undiscovered conventional crude oil production	MBbl
TECH_UGCOAL	Variable	Annual technical developing coalbed methane gas production	MMcf
TECH_UGSHALE	Variable	Annual technical developing shale gas production	MMcf
TECH_UGTIGHT	Variable	Annual technical developing tight gas production	MMcf
TECH_USHALE	Variable	Technical undiscovered shale gas production	MMcf
TECH_UTIGHT	Variable	Technical undiscovered tight gas production	MMcf
TECH_WATER	Variable	Technical production from waterflood	MBbl

TECH_WTRFLD	Variable	Technical production from waterflood	MBbl
TGGLCD	Variable	Total G & G cost	K$
TI	Variable	Tangible costs	K$
TI_DRL	Variable	Tangible drilling cost	K$
TIMED	Variable	Timing flag	
TIMEDYR	Variable	Year in which the project is timed	
TOC	Variable	Total operating costs	K$
TORECY	Variable	Annual water injection	MBbl
TORECY_CST	Variable	Water injection cost	K$
TOTHWCAP	Variable	Total horizontal drilling footage constraint	Ft
TOTINJ	Variable	Annual water injection	MBbl
TOTMUL	Input	Total drilling constraint multiplier	
TOTSTATE	Variable	Total state severance tax	K$
UCNT	Variable	Number of undiscovered reservoirs	
UDEPTH	Variable	Reservoir depth	K$
UMPCO2	Input	CO_2 ultimate market acceptance	
UNAME	Variable	Reservoir identifier	
UNDARES	Variable	Undiscovered resource, AD gas or lease condensate	Bcf, MMBbl
UNDRES	Variable	Undiscovered resource	MMBbl, Bcf
UREG	Variable	Reservoir region	
USE_AVAILCO2	Variable	Used annual volume of CO_2 by region	Bcf
USE_RDR	Input	Use rig depth rating	
USEAVAIL	Variable	Used annual CO_2 volume by region across all sources	Bcf
USECAP	Variable	Annual total capital investment constraints, used by projects	MM$
UVALUE	Variable	Reservoir undiscovered crude oil production	MBbl
UVALUE2	Variable	Reservoir undiscovered natural gas production	MMcf
VEORCP	Input	Volumetric EOR cutoff	%
VIABLE	Variable	The number of economically viable reservoirs	
VOL_SWP_ FAC	Input	Sweep volume factor	
VOL_SWP_CHG	Variable	Change in sweep volume	
WAT_OAM	Input	Process specific operating cost for water production	$/Bbl
WATINJ	Variable	Annual water injection	MBbl

WATPROD	Variable	Annual water production	MBbl
WELLSL48	Variable	Lower 48 onshore wells drilled	Wells
WINJ	Variable	Well level water injection	MBbl
WPROD	Variable	Well level water production	MBbl
WRK_W	Variable	Cost for well workover	K$
WRKA	Estimated	Constant for workover cost equations	
WRKB	Estimated	Constant for workover cost equations	
WRKC	Estimated	Constant for workover cost equations	
WRKD	Input	Maximum depth range for workover cost	Ft
WRKK	Estimated	Constant for workover cost equations	
WRKM	Input	Minimum depth range for workover cost	Ft
XCAPBASE	Variable	Cumulative cap stream	
XCUMPROD	Variable	Cumulative production	MBbl
XPATN	Variable	Active patterns each year	
XPP1	Variable	Number of new producers drilled per pattern	
XPP2	Variable	Number of new injectors drilled per pattern	
XPP3	Variable	Number of producers converted to injectors	
XPP4	Variable	Number of primary wells converted to secondary wells	
XROY	Input	Royalty rate	Percent
YEARS_STUDY	Input	Number of years of analysis	
YR1	Input	Number of years for tax credit on tangible investments	
YR2	Input	Number of years for tax credit on intangible investments	
YRDI	Input	Years to develop infrastructure	
YRDT	Input	Years to develop technology	
YRMA	Input	Years to reach full capacity	

Appendix 2.B: Cost and Constraint Estimation

The major sections of OLOGSS consist of a series of equations that are used to calculate project economics and the development of crude oil and natural gas resources subject to the availability of regional development constraints. The cost and constraint calculation was assessed as unit costs per well. The product of the cost equation and cost adjustment factor is the actual cost. The actual cost reflects the influence on the resource, region and oil or gas price. The equations, the estimation techniques, and the statistical results for these equations are documented below. The statistical software included within Microsoft Excel was used for the estimations.

Drilling and Completion Costs for Crude Oil

The 2004 – 2007 Joint Association Survey (JAS) data was used to calculate the equation for vertical drilling and completion costs for crude oil. The data was analyzed at a regional level. The independent variables were depth, raised to powers of 1 through 3. Drilling cost is the cost of drilling on a per well basis. Depth is also on a per well basis. The method of estimation used was ordinary least squares. The form of the equation is given below. β1 (the coefficient for depth raised to the first power) is statistically insignificant and is therefore assumed zero.

$$\text{Drilling Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}1)$$

where Drilling Cost = DWC_W

β0 = OIL_DWCK

β1 = OIL_DWCA

β2 = OIL_DWCB

β3 = OIL_DWCC

from equations 2-17 and 2-18 in Chapter 2.

Northeast Region:

Regression Statistics	
Multiple R	0.836438789
R Square	0.699629848
Adjusted R Square	0.691168717
Standard Error	629377.1735
Observations	74

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	6.55076E+13	3.27538E+13	82.6875087	2.86296E-19
Residual	71	2.81242E+13	3.96116E+11		
Total	73	9.36318E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	122428.578	126464.5594	0.968086068	0.336287616	-129734.7159	374591.8719	-129734.7159	374591.8719
β2	0.058292022	0.020819613	2.799860932	0.006580083	0.016778872	0.099805172	0.016778872	0.099805172
β3	5.68014E-07	2.56497E-06	0.221450391	0.825377435	-4.5464E-06	5.68243E-06	-4.5464E-06	5.68243E-06

Gulf Coast Region:

Regression Statistics	
Multiple R	0.927059199
R Square	0.859438758
Adjusted R Square	0.85771408
Standard Error	754021.7218
Observations	166

ANOVA

	df	SS	MS	F	Significance F
Regression	2	5.66637E+14	2.83318E+14	498.3184388	3.55668E-70
Residual	163	9.26734E+13	5.68549E+11		
Total	165	6.5931E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	171596.0907	99591.43949	1.723000407	0.086784881	-25059.61405	368251.7955	-25059.61405	368251.7955
β2	0.026582707	0.005213357	5.098961204	9.38664E-07	0.016288283	0.036877131	0.016288283	0.036877131
β3	5.10946E-07	3.82305E-07	1.336488894	0.183252113	-2.43962E-07	1.26585E-06	-2.43962E-07	1.26585E-06

Mid-Continent Region:

Regression Statistics	
Multiple R	0.898305188
R Square	0.806952211
Adjusted R Square	0.803343841
Standard Error	865339.0638
Observations	110

ANOVA

	df	SS	MS	F	Significance F
Regression	2	3.34919E+14	1.67459E+14	223.6334505	6.06832E-39
Residual	107	8.01229E+13	7.48812E+11		
Total	109	4.15042E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	44187.62539	135139.2151	0.326978556	0.744322892	-223710.0994	312085.3502	-223710.0994	312085.3502
β2	0.038468835	0.005870927	6.552429326	2.04023E-09	0.026830407	0.050107263	0.026830407	0.050107263
β3	-9.45921E-07	3.70017E-07	-2.556425591	0.011978314	-1.67944E-06	-2.12405E-07	-1.67944E-06	-2.12405E-07

Southwest Region:

Regression Statistics	
Multiple R	0.927059199
R Square	0.859438758
Adjusted R Square	0.85771408
Standard Error	754021.7218
Observations	166

ANOVA

	df	SS	MS	F	Significance F
Regression	2	5.66637E+14	2.83318E+14	498.3184388	3.55668E-70
Residual	163	9.26734E+13	5.68549E+11		
Total	165	6.5931E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	171596.0907	99591.43949	1.723000407	0.086784881	-25059.61405	368251.7955	-25059.61405	368251.7955
β2	0.026582707	0.005213357	5.098961204	9.38664E-07	0.016288283	0.036877131	0.016288283	0.036877131
β3	5.10946E-07	3.82305E-07	1.336488894	0.183252113	-2.43962E-07	1.26585E-06	-2.43962E-07	1.26585E-06

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.905358855
R Square	0.819674657
Adjusted R Square	0.81505093
Standard Error	1524859.577
Observations	81

ANOVA

	df	SS	MS	F	Significance F
Regression	2	8.24402E+14	4.12201E+14	177.2757561	9.68755E-30
Residual	78	1.81365E+14	2.3252E+12		
Total	80	1.00577E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	85843.77642	334865.8934	0.256352702	0.798353427	-580822.9949	752510.5477	-580822.9949	752510.5477
β2	0.024046279	0.017681623	1.35995883	0.177760898	-0.011155127	0.059247685	-0.011155127	0.059247685
β3	3.11588E-06	1.35985E-06	2.291329746	0.024643617	4.08613E-07	5.82314E-06	4.08613E-07	5.82314E-06

West Coast Region:

Regression Statistics	
Multiple R	0.829042211
R Square	0.687310988
Adjusted R Square	0.66961161
Standard Error	1192282.08
Observations	57

ANOVA

	df	SS	MS	F	Significance F
Regression	3	1.65605E+14	5.52018E+13	38.83249387	2.05475E-13
Residual	53	7.53414E+13	1.42154E+12		
Total	56	2.40947E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	416130.9988	739996.4118	0.562341914	0.576253925	-1068113.806	1900375.804	-1068113.806	1900375.804
β1	44.24458907	494.4626992	0.089480135	0.929037628	-947.5219666	1036.011145	-947.5219666	1036.011145
β2	0.032683532	0.091113678	0.35871159	0.721235869	-0.150067358	0.215434422	-0.150067358	0.215434422
β3	3.38129E-07	4.76464E-06	0.070966208	0.94369176	-9.21853E-06	9.89479E-06	-9.21853E-06	9.89479E-06

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.847120174
R Square	0.71761259
Adjusted R Square	0.702750095
Standard Error	1967213.576
Observations	61

ANOVA

	df	SS	MS	F	Significance F
Regression	3	5.60561E+14	1.86854E+14	48.2834529	1.1626E-15
Residual	57	2.20586E+14	3.86993E+12		
Total	60	7.81147E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	98507.54357	1384010.586	0.071175426	0.943507284	-2672925.83	2869940.917	-2672925.83	2869940.917
β1	478.7358996	548.203512	0.873281344	0.386173991	-619.0226893	1576.494489	-619.0226893	1576.494489
β2	-0.00832112	0.058193043	-0.142991666	0.886801051	-0.124850678	0.108208438	-0.124850678	0.108208438
β3	6.1159E-07	1.79131E-06	0.34142064	0.7340424	-2.97545E-06	4.19863E-06	-2.97545E-06	4.19863E-06

Drilling and Completion Cost for Oil - Cost Adjustment Factor

The cost adjustment factor for vertical drilling and completion costs for oil was calculated using JAS data through 2007. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Northeast Region:

Regression Statistics	
Multiple R	0.993325966
R Square	0.986696475
Adjusted R Square	0.986411399
Standard Error	0.029280014
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.901997029	2.967332343	3461.175482	4.4887E-131
Residual	140	0.120024694	0.000857319		
Total	143	9.022021723			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.309616442	0.009839962	31.46520591	2.3349E-65	0.290162308	0.329070576	0.290162308	0.329070576
β1	0.019837121	0.000434252	45.68110123	5.41725E-86	0.018978581	0.020695661	0.018978581	0.020695661
β2	-0.000142411	5.21769E-06	-27.29392193	6.44605E-58	-0.000152727	-0.000132095	-0.000152727	-0.000132095
β3	3.45898E-07	1.69994E-08	20.34770764	1.18032E-43	3.1229E-07	3.79507E-07	3.1229E-07	3.79507E-07

Gulf Coast Region:

Regression Statistics	
Multiple R	0.975220111
R Square	0.951054265
Adjusted R Square	0.950005428
Standard Error	0.054224144
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	7.998414341	2.666138114	906.7701736	1.76449E-91
Residual	140	0.411636098	0.002940258		
Total	143	8.410050438			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.404677859	0.01822279	22.2072399	1.01029E-47	0.368650426	0.440705292	0.368650426	0.440705292
β1	0.016335847	0.000804199	20.31319148	1.41023E-43	0.014745903	0.017925792	0.014745903	0.017925792
β2	-0.00010587	9.66272E-06	-10.95654411	1.47204E-20	-0.000124974	-8.67663E-05	-0.000124974	-8.67663E-05
β3	2.40517E-07	3.14814E-08	7.639970947	3.10789E-12	1.78277E-07	3.02758E-07	1.78277E-07	3.02758E-07

Mid-Continent Region:

Regression Statistics	
Multiple R	0.973577019
R Square	0.947852212
Adjusted R Square	0.94673476
Standard Error	0.058882142
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.822668656	2.940889552	848.2258794	1.4872E-89
Residual	140	0.485394925	0.003467107		
Total	143	9.308063582			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.309185338	0.019788175	15.62475232	1.738E-32	0.270063053	0.348307623	0.270063053	0.348307623
β1	0.019036286	0.000873282	21.79856116	7.62464E-47	0.017309761	0.020762811	0.017309761	0.020762811
β2	-0.000123667	1.04928E-05	-11.78593913	1.05461E-22	-0.000144412	-0.000102922	-0.000144412	-0.000102922
β3	2.60516E-07	3.41858E-08	7.620611936	3.45556E-12	1.92929E-07	3.28104E-07	1.92929E-07	3.28104E-07

Southwest Region:

Regression Statistics	
Multiple R	0.993452577
R Square	0.986948023
Adjusted R Square	0.986668338
Standard Error	0.030207623
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.66004438	3.220014793	3528.781511	1.1799E-131
Residual	140	0.127750066	0.0009125		
Total	143	9.787794446			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.293837119	0.010151698	28.944627	5.92751E-61	0.273766667	0.313907571	0.273766667	0.313907571
β1	0.020183122	0.00044801	45.05064425	3.35207E-85	0.019297383	0.021068861	0.019297383	0.021068861
β2	-0.000142936	5.38299E-06	-26.55334755	1.63279E-56	-0.000153579	-0.000132294	-0.000153579	-0.000132294
β3	3.44926E-07	1.75379E-08	19.66744699	4.04901E-42	3.10253E-07	3.796E-07	3.10253E-07	3.796E-07

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.993622433
R Square	0.987285538
Adjusted R Square	0.987013086
Standard Error	0.029478386
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.446702681	3.148900894	3623.69457	1.8856E-132
Residual	140	0.121656535	0.000868975		
Total	143	9.568359216			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.297270516	0.009906628	30.00723517	7.63744E-63	0.27768458	0.316856451	0.27768458	0.316856451
β1	0.020126228	0.000437194	46.03497443	1.9664E-86	0.019261872	0.020990585	0.019261872	0.020990585
β2	-0.000143079	5.25304E-06	-27.23739215	8.23219E-58	-0.000153465	-0.000132693	-0.000153465	-0.000132693
β3	3.45557E-07	1.71145E-08	20.19080817	2.6538E-43	3.1172E-07	3.79393E-07	3.1172E-07	3.79393E-07

West Coast Region:

Regression Statistics	
Multiple R	0.993362569
R Square	0.986769193
Adjusted R Square	0.986485676
Standard Error	0.030158697
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.496912448	3.165637483	3480.455028	3.0585E-131
Residual	140	0.127336582	0.000909547		
Total	143	9.62424903			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.297702178	0.010135256	29.37293095	1.01194E-61	0.277664233	0.317740124	0.277664233	0.317740124
β1	0.020091425	0.000447284	44.91872099	4.92225E-85	0.019207121	0.02097573	0.019207121	0.02097573
β2	-0.000142627	5.37427E-06	-26.53879345	1.74092E-56	-0.000153252	-0.000132001	-0.000153252	-0.000132001
β3	3.44597E-07	1.75095E-08	19.68054067	3.78057E-42	3.0998E-07	3.79214E-07	3.0998E-07	3.79214E-07

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.993744864
R Square	0.987528854
Adjusted R Square	0.987261615
Standard Error	0.029293844
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.513146663	3.171048888	3695.304354	4.8762E-133
Residual	140	0.1201381	0.000858129		
Total	143	9.633284764			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.292784596	0.00984461	29.74059899	2.25193E-62	0.273321274	0.312247919	0.273321274	0.312247919
β1	0.020415818	0.000434457	46.99153447	1.31433E-87	0.019556872	0.021274763	0.019556872	0.021274763
β2	-0.000146385	5.22015E-06	-28.04230529	2.6131E-59	-0.000156706	-0.000136065	-0.000156706	-0.000136065
β3	3.5579E-07	1.70074E-08	20.91972526	6.3186E-45	3.22166E-07	3.89415E-07	3.22166E-07	3.89415E-07

Drilling and Completion Costs for Natural Gas

The 2004 – 2007 JAS data was used to calculate the equation for vertical drilling and completion costs for natural gas. The data was analyzed at a regional level. The independent variable was depth. Drilling cost is the cost of drilling on a per well basis. Depth is also on a per well basis. The method of estimation used was ordinary least squares. The form of the equation is given below.

$$\text{Drilling Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \qquad (2.B\text{-}2)$$

where Drilling Cost = DWC_W

β0 = GAS_DWCK

β1 = GAS_DWCA

β2 = GAS_DWCB

β3 = GAS_DWCC

from equations 2-24 and 2-25 in Chapter 2.

Northeast Region:

Regression Statistics	
Multiple R	0.837701882
R Square	0.701744444
Adjusted R Square	0.694887994
Standard Error	1199562.042
Observations	90

ANOVA

	df	SS	MS	F	Significance F
Regression	2	2.94547E+14	1.47274E+14	102.3480792	1.39509E-23
Residual	87	1.25189E+14	1.43895E+12		
Total	89	4.19736E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	197454.5012	290676.607	0.679292714	0.498755704	-380296.7183	775205.7207	-380296.7183	775205.7207
β1	19.31146768	128.263698	0.150560665	0.880670823	-235.6265154	274.2494508	-235.6265154	274.2494508
β2	0.040120878	0.009974857	4.022200679	0.000122494	0.020294769	0.059946987	0.020294769	0.059946987

Gulf Coast Region:

Regression Statistics	
Multiple R	0.842706997
R Square	0.710155083
Adjusted R Square	0.708248209
Standard Error	2573551.438
Observations	307

ANOVA

	df	SS	MS	F	Significance F
Regression	2	4.93318E+15	2.46659E+15	372.4183744	1.77494E-82
Residual	304	2.01344E+15	6.62317E+12		
Total	306	6.94662E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	318882.7578	272026.272	1.172249855	0.242014577	-216410.0169	854175.5325	-216410.0169	854175.5325
β2	0.019032113	0.008289474	2.295937192	0.022359763	0.002720101	0.035344125	0.002720101	0.035344125
β3	1.12638E-06	4.6744E-07	2.409676918	0.016560642	2.06552E-07	2.04621E-06	2.06552E-07	2.04621E-06

Mid-Continent Region:

Regression Statistics	
Multiple R	0.92348831
R Square	0.852830659
Adjusted R Square	0.850494637
Standard Error	1309841.335
Observations	129

ANOVA

	df	SS	MS	F	Significance F
Regression	2	1.25272E+15	6.26359E+14	365.0782904	3.73674E-53
Residual	126	2.16176E+14	1.71568E+12		
Total	128	1.46889E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	355178.8049	240917.4549	1.47427593	0.142901467	-121589.7497	831947.3594	-121589.7497	831947.3594
β1	54.21184769	45.96361807	1.17945127	0.240440741	-36.74880003	145.1724954	-36.74880003	145.1724954
β3	1.20269E-06	1.12352E-07	10.70467954	2.04711E-19	9.80347E-07	1.42503E-06	9.80347E-07	1.42503E-06

Southwest Region:

Regression Statistics	
Multiple R	0.915492169
R Square	0.838125912
Adjusted R Square	0.834866702
Standard Error	1386872.99
Observations	153

ANOVA

	df	SS	MS	F	Significance F
Regression	3	1.48386E+15	4.94618E+14	257.1561693	1.088E-58
Residual	149	2.86589E+14	1.92342E+12		
Total	152	1.77044E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	91618.176	571133.886	0.160414534	0.872771817	-1036949.89	1220186.242	-1036949.89	1220186.242
β1	376.1968481	269.4896391	1.395960339	0.164802951	-156.3182212	908.7119175	-156.3182212	908.7119175
β2	-0.062403125	0.034837969	-1.791238896	0.075284827	-0.131243411	0.00643716	-0.131243411	0.00643716
β3	5.03882E-06	1.29778E-06	3.88265606	0.000154832	2.4744E-06	7.60325E-06	2.4744E-06	7.60325E-06

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.936745489
R Square	0.877492112
Adjusted R Square	0.87539796
Standard Error	2403080.549
Observations	120

ANOVA

	df	SS	MS	F	Significance F
Regression	2	4.83951E+15	2.41976E+15	419.0202716	4.54566E-54
Residual	117	6.75651E+14	5.7748E+12		
Total	119	5.51516E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	219733.2637	346024.9678	0.635021412	0.526654367	-465551.0299	905017.5572	-465551.0299	905017.5572
β2	0.032265399	0.013130355	2.457313594	0.015464796	0.00626142	0.058269377	0.00626142	0.058269377
β3	2.6019E-06	7.88034E-07	3.301759413	0.001274492	1.04124E-06	4.16256E-06	1.04124E-06	4.16256E-06

West Coast Region:

Regression Statistics	
Multiple R	0.901854712
R Square	0.813341922
Adjusted R Square	0.795564962
Standard Error	494573.0787
Observations	24

ANOVA

	df	SS	MS	F	Significance F
Regression	2	2.23824E+13	1.11912E+13	45.75258814	2.21815E-08
Residual	21	5.13665E+12	2.44603E+11		
Total	23	2.75191E+13			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	385532.8938	215673.5911	1.787575808	0.088286514	-62984.89058	834050.6782	-62984.89058	834050.6782
β2	0.01799366	0.016370041	1.099182335	0.284130777	-0.016049704	0.052037025	-0.016049704	0.052037025
β3	1.01127E-06	1.49488E-06	0.676491268	0.506112235	-2.0975E-06	4.12005E-06	-2.0975E-06	4.12005E-06

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.856130745
R Square	0.732959853
Adjusted R Square	0.706255838
Standard Error	2157271.229
Observations	23

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	2.55472E+14	1.27736E+14	27.44755272	1.84402E-06
Residual	20	9.30764E+13	4.65382E+12		
Total	22	3.48548E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	267619.9291	1118552.942	0.239255487	0.813342236	-2065640.615	2600880.473	-2065640.615	2600880.473
β1	30.61609506	550.5220307	0.055612843	0.956202055	-1117.752735	1178.984925	-1117.752735	1178.984925
β2	0.049406678	0.035529716	1.390573371	0.179635875	-0.024707012	0.123520367	-0.024707012	0.123520367

Drilling and Completion Cost for Gas - Cost Adjustment Factor

The cost adjustment factor for vertical drilling and completion costs for gas was calculated using JAS data through 2007. The initial cost was normalized at various prices from $1 to $20 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $5 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Gas Price} + \beta 2 * \text{Gas Price}^2 + \beta 3 * \text{Gas Price}^3$$

Northeast Region:

Regression Statistics	
Multiple R	0.988234523
R Square	0.976607472
Adjusted R Square	0.976106203
Standard Error	0.03924461
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.001833192	3.000611064	1948.272332	6.4218E-114
Residual	140	0.215619522	0.001540139		
Total	143	9.217452714			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.315932281	0.013188706	23.95476038	2.2494E-51	0.289857502	0.34200706	0.289857502	0.34200706
β1	0.195760743	0.005820373	33.63371152	6.11526E-69	0.184253553	0.207267932	0.184253553	0.207267932
β2	-0.013906425	0.000699337	-19.88514708	1.29788E-42	-0.015289053	-0.012523798	-0.015289053	-0.012523798
β3	0.000336178	2.27846E-05	14.75458424	2.61104E-30	0.000291131	0.000381224	0.000291131	0.000381224

Gulf Coast Region:

Regression Statistics	
Multiple R	0.976776879
R Square	0.954093072
Adjusted R Square	0.953109352
Standard Error	0.051120145
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	7.60369517	2.534565057	969.8828784	1.98947E-93
Residual	140	0.365857688	0.002613269		
Total	143	7.969552858			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.343645899	0.017179647	20.00308313	7.02495E-43	0.309680816	0.377610983	0.309680816	0.377610983
β1	0.190338822	0.007581635	25.10524794	1.08342E-53	0.175349523	0.205328121	0.175349523	0.205328121
β2	-0.013965513	0.000910959	-15.33056399	9.3847E-32	-0.015766527	-0.012164498	-0.015766527	-0.012164498
β3	0.000342962	2.96793E-05	11.55560459	4.15963E-22	0.000284285	0.00040164	0.000284285	0.00040164

Mid-continent Region:

Regression Statistics	
Multiple R	0.973577019
R Square	0.947852212
Adjusted R Square	0.94673476
Standard Error	0.058882142
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.822668656	2.940889552	848.2258794	1.4872E-89
Residual	140	0.485394925	0.003467107		
Total	143	9.308063582			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.309185338	0.019788175	15.62475232	1.738E-32	0.270063053	0.348307623	0.270063053	0.348307623
β1	0.019036286	0.000873282	21.79856116	7.62464E-47	0.017309761	0.020762811	0.017309761	0.020762811
β2	-0.000123667	1.04928E-05	-11.78593913	1.05461E-22	-0.000144412	-0.000102922	-0.000144412	-0.000102922
β3	2.60516E-07	3.41858E-08	7.620611936	3.45556E-12	1.92929E-07	3.28104E-07	1.92929E-07	3.28104E-07

Southwest Region:

Regression Statistics	
Multiple R	0.966438524
R Square	0.934003421
Adjusted R Square	0.932589209
Standard Error	0.06631093
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.712149531	2.904049844	660.4406967	2.13407E-82
Residual	140	0.615599523	0.004397139		
Total	143	9.327749054			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.323862308	0.022284725	14.53292844	9.46565E-30	0.279804211	0.367920404	0.279804211	0.367920404
β1	0.193832047	0.009834582	19.70923084	3.2532E-42	0.174388551	0.213275544	0.174388551	0.213275544
β2	-0.013820723	0.001181658	-11.69604336	1.80171E-22	-0.016156924	-0.011484522	-0.016156924	-0.011484522
β3	0.000334693	3.84988E-05	8.693602923	8.44808E-15	0.000258579	0.000410807	0.000258579	0.000410807

Rocky Mountains Region:

Regression Statistics	
Multiple R	0.985593617
R Square	0.971394777
Adjusted R Square	0.970781808
Standard Error	0.0421446
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.444274294	2.814758098	1584.737059	8.3614E-108
Residual	140	0.248663418	0.001776167		
Total	143	8.692937712			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.32536782	0.014163288	22.97261928	2.42535E-49	0.29736624	0.353369401	0.29736624	0.353369401
β1	0.194045615	0.006250471	31.04496067	1.21348E-64	0.181688099	0.206403131	0.181688099	0.206403131
β2	-0.01396687	0.000751015	-18.59732564	1.18529E-39	-0.015451667	-0.012482073	-0.015451667	-0.012482073
β3	0.000339698	2.44683E-05	13.88318297	4.22503E-28	0.000291323	0.000388073	0.000291323	0.000388073

West Coast Region:

Regression Statistics	
Multiple R	0.994143406
R Square	0.988321112
Adjusted R Square	0.98807085
Standard Error	0.026802603
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.510960152	2.836986717	3949.147599	4.9307E-135
Residual	140	0.100573131	0.00071838		
Total	143	8.611533284			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.325917293	0.009007393	36.18330938	6.29717E-73	0.308109194	0.343725393	0.308109194	0.343725393
β1	0.193657091	0.003975097	48.71757347	1.12458E-89	0.185798111	0.201516072	0.185798111	0.201516072
β2	-0.013893214	0.000477621	-29.08835053	3.2685E-61	-0.014837497	-0.012948932	-0.014837497	-0.012948932
β3	0.000337413	1.5561E-05	21.68318808	1.35414E-46	0.000306648	0.000368178	0.000306648	0.000368178

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.970035104
R Square	0.940968103
Adjusted R Square	0.939703134
Standard Error	0.057035843
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	7.259587116	2.419862372	743.8663996	8.71707E-86
Residual	140	0.455432229	0.003253087		
Total	143	7.715019345			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.352772153	0.0191677	18.40451098	3.34838E-39	0.31487658	0.390667726	0.31487658	0.390667726
β1	0.189510541	0.008458993	22.40344064	3.85701E-48	0.172786658	0.206234423	0.172786658	0.206234423
β2	-0.014060192	0.001016376	-13.83364754	5.65155E-28	-0.016069622	-0.012050761	-0.016069622	-0.012050761
β3	0.000347364	3.31138E-05	10.49000322	2.34854E-19	0.000281896	0.000412832	0.000281896	0.000412832

Drilling and Completion Costs for Dryholes

The 2004 – 2007 JAS data was used to calculate the equation for vertical drilling and completion costs for dryholes. The data was analyzed at a regional level. The independent variable was depth. Drilling cost is the cost of drilling on a per well basis. Depth is also on a per well basis. The method of estimation used was ordinary least squares. The form of the equation is given bellow.

$$\text{Drilling Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \qquad (2.B\text{-}3)$$

where Drilling Cost = DWC_W
β0 = DRY_DWCK
β1 = DRY_DWCA
β2 = DRY_DWCB
β3 = DRY_DWCC
from equations 2-19 and 2-20 in Chapter 2.

Northeast Region:

Regression Statistics	
Multiple R	0.913345218
R Square	0.834199487
Adjusted R Square	0.828851084
Standard Error	1018952.27
Observations	97

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	4.85819E+14	1.6194E+14	155.9716777	3.64706E-36
Residual	93	9.65585E+13	1.03826E+12		
Total	96	5.82378E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	170557.6447	323739.1839	0.526836581	0.599561475	-472323.5706	813438.8601	-472323.5706	813438.8601
β1	256.9930321	233.0025772	1.102962187	0.272889552	-205.7034453	719.6895095	-205.7034453	719.6895095
β2	-0.043428533	0.043117602	-1.007211224	0.31644672	-0.129051459	0.042194394	-0.129051459	0.042194394
β3	5.9031E-06	2.11581E-06	2.789995653	0.006394574	1.70153E-06	1.01047E-05	1.70153E-06	1.01047E-05

Gulf Coast Region:

Regression Statistics	
Multiple R	0.868545327
R Square	0.754370985
Adjusted R Square	0.752096642
Standard Error	2529468.051
Observations	328

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	6.36662E+15	2.12221E+15	331.6874692	2.10256E-98
Residual	324	2.07302E+15	6.39821E+12		
Total	327	8.43964E+15			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	118790.7619	515360.6337	0.230500264	0.81784853	-895084.76	1132666.284	-895084.76	1132666.284
β1	126.2333724	241.1698405	0.523421055	0.601039076	-348.2231187	600.6898634	-348.2231187	600.6898634
β2	-0.001057252	0.0294162	-0.035941139	0.971351426	-0.058928115	0.056813612	-0.058928115	0.056813612
β3	2.32104E-06	1.0194E-06	2.276864977	0.02344596	3.15558E-07	4.32653E-06	3.15558E-07	4.32653E-06

Mid-Continent Region:

Regression Statistics	
Multiple R	0.80373002
R Square	0.645981944
Adjusted R Square	0.636056204
Standard Error	904657.9939
Observations	111

ANOVA

	df	SS	MS	F	Significance F
Regression	3	1.59789E+14	5.32631E+13	65.08149035	5.0095E-24
Residual	107	8.75695E+13	8.18406E+11		
Total	110	2.47359E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	163849.8824	309404.7345	0.529564884	0.597510699	-449508.8999	777208.6646	-449508.8999	777208.6646
β1	17.95111978	155.7546455	0.115252548	0.908460959	-290.8142902	326.7165297	-290.8142902	326.7165297
β2	0.022715716	0.021144885	1.074288957	0.285109837	-0.019201551	0.064632983	-0.019201551	0.064632983
β3	-3.50301E-07	7.90957E-07	-0.442882115	0.658745077	-1.91828E-06	1.21768E-06	-1.91828E-06	1.21768E-06

Southwest Region:

Regression Statistics	
Multiple R	0.916003396
R Square	0.839062222
Adjusted R Square	0.835290243
Standard Error	734795.4183
Observations	132

ANOVA

	df	SS	MS	F	Significance F
Regression	3	3.60312E+14	1.20104E+14	222.4461445	1.40193E-50
Residual	128	6.91103E+13	5.39924E+11		
Total	131	4.29423E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	22628.66985	252562.1046	0.089596457	0.928747942	-477108.2352	522365.5749	-477108.2352	522365.5749
β1	262.7649266	164.1391792	1.600866581	0.111871702	-62.01224262	587.5420958	-62.01224262	587.5420958
β2	-0.064989728	0.029352301	-2.21412721	0.02859032	-0.123068227	-0.006911229	-0.123068227	-0.006911229
β3	6.52693E-06	1.49073E-06	4.378340081	2.46095E-05	3.57727E-06	9.4766E-06	3.57727E-06	9.4766E-06

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.908263682
R Square	0.824942917
Adjusted R Square	0.821295894
Standard Error	1868691.311
Observations	99

ANOVA

	df	SS	MS	F	Significance F
Regression	2	1.57976E+15	7.89879E+14	226.1962739	4.70571E-37
Residual	96	3.35233E+14	3.49201E+12		
Total	98	1.91499E+15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	288056.5506	314517.8483	0.915867103	0.362031526	-336256.4285	912369.5298	-336256.4285	912369.5298
β2	0.018141347	0.017298438	1.048727458	0.296936644	-0.01619578	0.052478474	-0.01619578	0.052478474
β3	3.85847E-06	1.27201E-06	3.033362592	0.003110773	1.33355E-06	6.3834E-06	1.33355E-06	6.3834E-06

West Coast Region:

Regression Statistics	
Multiple R	0.853182771
R Square	0.727920841
Adjusted R Square	0.707514904
Standard Error	907740.218
Observations	44

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.81804E+13	2.93935E+13	35.67201271	2.18647E-11
Residual	40	3.29597E+13	8.23992E+11		
Total	43	1.2114E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	106996.0572	512960.104	0.208585534	0.835830348	-929734.9747	1143727.089	-929734.9747	1143727.089
β1	687.3095347	329.4149478	2.086455212	0.043357214	21.53709715	1353.081972	21.53709715	1353.081972
β2	-0.15898723	0.058188911	-2.732259905	0.009317504	-0.276591406	-0.041383054	-0.276591406	-0.041383054
β3	1.14978E-05	2.91968E-06	3.938046272	0.000320309	5.59694E-06	1.73987E-05	5.59694E-06	1.73987E-05

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.841621294
R Square	0.708326403
Adjusted R Square	0.687977082
Standard Error	2155533.512
Observations	47

ANOVA

	df	SS	MS	F	Significance F
Regression	3	4.85193E+14	1.61731E+14	34.80835607	1.41404E-11
Residual	43	1.99792E+14	4.64632E+12		
Total	46	6.84985E+14			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	122507.9534	1373015.289	0.089225484	0.929317007	-2646441.235	2891457.142	-2646441.235	2891457.142
β1	345.4371452	801.6324436	0.430917122	0.668681154	-1271.20873	1962.08302	-1271.20873	1962.08302
β2	-0.014734575	0.126273194	-0.11668807	0.907650548	-0.269388738	0.239919588	-0.269388738	0.239919588
β3	3.23748E-06	5.69952E-06	0.568026219	0.572971531	-8.2567E-06	1.47317E-05	-8.2567E-06	1.47317E-05

Drilling and Completion Cost for Dry - Cost Adjustment Factor

The cost adjustment factor for vertical drilling and completion costs for dryholes was calculated using JAS data through 2007. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Northeast Region:

Regression Statistics	
Multiple R	0.994846264
R Square	0.989719089
Adjusted R Square	0.989498783
Standard Error	0.026930376
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.774469405	3.258156468	4492.489925	6.5663E-139
Residual	140	0.101534319	0.000725245		
Total	143	9.876003725			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.290689859	0.009050333	32.11924425	1.85582E-66	0.272796865	0.308582854	0.272796865	0.308582854
β1	0.020261651	0.000399405	50.72962235	5.26469E-92	0.019472006	0.021051296	0.019472006	0.021051296
β2	-0.000143294	4.79898E-06	-29.85918012	1.391E-62	-0.000152782	-0.000133806	-0.000152782	-0.000133806
β3	3.45487E-07	1.56352E-08	22.09672004	1.74153E-47	3.14575E-07	3.76399E-07	3.14575E-07	3.76399E-07

Gulf Coast Region:

Regression Statistics	
Multiple R	0.993347128
R Square	0.986738516
Adjusted R Square	0.986454342
Standard Error	0.031666016
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.44539464	3.481798214	3472.296057	3.5967E-131
Residual	140	0.140383119	0.001002737		
Total	143	10.58577776			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.277940175	0.010641812	26.11774938	1.12431E-55	0.256900742	0.298979608	0.256900742	0.298979608
β1	0.020529977	0.000469639	43.71437232	1.71946E-83	0.019601475	0.021458479	0.019601475	0.021458479
β2	-0.000143466	5.64287E-06	-25.42421447	2.53682E-54	-0.000154622	-0.000132309	-0.000154622	-0.000132309
β3	3.43878E-07	1.83846E-08	18.70465533	6.66256E-40	3.07531E-07	3.80226E-07	3.07531E-07	3.80226E-07

Mid-Continent Region:

Regression Statistics	
Multiple R	0.984006541
R Square	0.968268874
Adjusted R Square	0.967588921
Standard Error	0.048034262
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.856909541	3.285636514	1424.023848	1.1869E-104
Residual	140	0.323020652	0.00230729		
Total	143	10.17993019			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.289971748	0.016142592	17.96314638	3.67032E-38	0.258056977	0.32188652	0.258056977	0.32188652
β1	0.020266191	0.000712397	28.44789972	4.71502E-60	0.018857744	0.021674637	0.018857744	0.021674637
β2	-0.000143007	8.55969E-06	-16.70702184	3.8001E-35	-0.00015993	-0.000126084	-0.00015993	-0.000126084
β3	3.44462E-07	2.78877E-08	12.35174476	3.63124E-24	2.89326E-07	3.99597E-07	2.89326E-07	3.99597E-07

Southwest Region:

Regression Statistics	
Multiple R	0.993309425
R Square	0.986663613
Adjusted R Square	0.986377833
Standard Error	0.031536315
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.30103457	3.43367819	3452.531986	5.3348E-131
Residual	140	0.139235479	0.000994539		
Total	143	10.44027005			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.278136296	0.010598224	26.24367047	6.42248E-56	0.257183038	0.299089554	0.257183038	0.299089554
β1	0.020381432	0.000467715	43.57656163	2.59609E-83	0.019456733	0.02130613	0.019456733	0.02130613
β2	-0.00014194	5.61976E-06	-25.25738215	5.41293E-54	-0.000153051	-0.00013083	-0.000153051	-0.00013083
β3	3.38578E-07	1.83093E-08	18.49210412	2.08785E-39	3.0238E-07	3.74777E-07	3.0238E-07	3.74777E-07

Rocky Mountain Region:

Regression Statistics	
Multiple R	0.9949703
R Square	0.9899658
Adjusted R Square	0.9897508
Standard Error	0.0266287
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.79418782	3.2647293	4604.11	1.199E-139
Residual	140	0.09927263	0.0007091		
Total	143	9.89346045			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.2902761	0.00894897	32.436833	5.504E-67	0.27258355	0.3079687	0.2725836	0.3079687
β1	0.0202676	0.00039493	51.319418	1.133E-92	0.01948684	0.0210484	0.0194868	0.0210484
β2	-0.0001433	4.7452E-06	-30.194046	3.595E-63	-0.0001527	-0.0001339	-0.0001527	-0.0001339
β3	3.454E-07	1.546E-08	22.340389	5.253E-48	3.1482E-07	3.76E-07	3.148E-07	3.76E-07

West Coast Region:

Regression Statistics	
Multiple R	0.992483684
R Square	0.985023864
Adjusted R Square	0.984702946
Standard Error	0.032081124
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	9.477071064	3.159023688	3069.401798	1.7868E-127
Residual	140	0.144087788	0.001029198		
Total	143	9.621158852			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.297817853	0.010781315	27.62351924	1.55941E-58	0.276502615	0.31913309	0.276502615	0.31913309
β1	0.020092432	0.000475796	42.22913162	1.54864E-81	0.019151759	0.021033105	0.019151759	0.021033105
β2	-0.000142719	5.71684E-06	-24.96465108	2.06229E-53	-0.000154021	-0.000131416	-0.000154021	-0.000131416
β3	3.44906E-07	1.86256E-08	18.51777816	1.81824E-39	3.08082E-07	3.81729E-07	3.08082E-07	3.81729E-07

Northern Great Plains Region:

Regression Statistics	
Multiple R	0.993525621
R Square	0.987093159
Adjusted R Square	0.986816584
Standard Error	0.031179889
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.40915184	3.469717279	3568.986978	5.3943E-132
Residual	140	0.136105966	0.000972185		
Total	143	10.5452578			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.281568556	0.010478442	26.87122338	4.04796E-57	0.260852113	0.302284998	0.260852113	0.302284998
β1	0.020437386	0.000462429	44.19569691	4.11395E-84	0.019523138	0.021351633	0.019523138	0.021351633
β2	-0.000142671	5.55624E-06	-25.67758357	8.07391E-55	-0.000153656	-0.000131686	-0.000153656	-0.000131686
β3	3.42012E-07	1.81024E-08	18.89319503	2.43032E-40	3.06223E-07	3.77802E-07	3.06223E-07	3.77802E-07

Drilling and Completion Costs for Horizontal Wells

The costs of horizontal drilling for crude oil, natural gas, and dryholes are based upon cost estimates developed for the Department of Energy's Comprehensive Oil and Gas Analysis Model. The form of the equation is as follows:

$$Cost = \beta 0 + \beta 1 * Depth^2 + \beta 2 * Depth^2 * nlat + \beta 3 * Depth^2 * nlat * latlen \qquad (2.B\text{-}4)$$

Where, nlat is the number of laterals per pattern and latlen is the length of those laterals. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Regression Statistics	
Multiple R	1
R Square	1
Adjusted R Square	1
Standard Error	3.12352E-12
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	147,510,801.46	49,170,267.15	5.04E+30	0.00
Residual	116	0.00	0.00		
Total	119	147,510,801.46			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	172.88	4.37E-13	3.95E+14	0.00	172.88	172.88	172.88	172.88
β1	8.07E-06	8.81E-21	9.16E+14	0.00	8.07E-06	8.07E-06	8.07E-06	8.07E-06
β2	1.15E-06	3.20E-21	3.60E+14	0.00	1.15E-06	1.15E-06	1.15E-06	1.15E-06
β3	9.22E-10	1.48E-24	6.23E+14	0.00	9.22E-10	9.22E-10	9.22E-10	9.22E-10

Cost to Equip a Primary Producer

The cost to equip a primary producer was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). The cost to equip a primary producer is equal to the grand total cost minus the producing equipment subtotal. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}5)$$

where Cost = NPR_W
β0 = NPRK
β1 = NPRA
β2 = NPRB
β3 = NPRC
from equation 2-21 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS regions 2 and 4:

Regression Statistics	
Multiple R	0.921
R Square	0.849
Adjusted R Square	0.697
Standard Error	621.17
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2,163,010.81	2,163,010.81	5.61	0.254415
Residual	1	385,858.01	385,858.01		
Total	2	2,548,868.81			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	51,315.4034	760.7805	67.4510	0.0094	41,648.8117	60,981.9952	41,648.8117	60,981.9952
β1	0.3404	0.1438	2.3676	0.2544	-1.4864	2.1672	-1.4864	2.1672

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.995
R Square	0.990
Adjusted R Square	0.981
Standard Error	1,193.14
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	145,656,740.81	145,656,740.81	102.32	0.06
Residual	1	1,423,576.87	1,423,576.87		
Total	2	147,080,317.68			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	45,821.717	1,461.289	31.357	0.020	27,254.360	64,389.074	27,254.360	64,389.074
β1	2.793	0.276	10.115	0.063	-0.716	6.302	-0.716	6.302

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9998
R Square	0.9995
Adjusted R Square	0.9990
Standard Error	224.46
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	105,460,601.42	105,460,601.42	2,093.17	0.01
Residual	1	50,383.23	50,383.23		
Total	2	105,510,984.64			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	62,709.378	274.909	228.110	0.003	59,216.346	66,202.411	59,216.346	66,202.411
β1	2.377	0.052	45.751	0.014	1.717	3.037	1.717	3.037

West Coast, applied to OLOGSS regions 6:

Regression Statistics	
Multiple R	0.9095
R Square	0.8272
Adjusted R Square	0.7408
Standard Error	2,257.74
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	48,812,671.60	48,812,671.60	9.58	0.09
Residual	2	10,194,785.98	5,097,392.99		
Total	3	59,007,457.58			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	106,959.788	2,219.144	48.199	0.000	97,411.576	116,508.001	97,411.576	116,508.001
β1	0.910	0.294	3.095	0.090	-0.355	2.174	-0.355	2.174

Cost to Equip a Primary Producer - Cost Adjustment Factor

The cost adjustment factor for the cost to equip a primary producer was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994410537
R Square	0.988852316
Adjusted R Square	0.988613437
Standard Error	0.026443679
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.683975313	2.894658438	4139.554242	1.896E-136
Residual	140	0.097897541	0.000699268		
Total	143	8.781872854			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.31969898	0.008886772	35.97470366	1.30857E-72	0.302129355	0.337268604	0.302129355	0.337268604
β1	0.01951727	0.000392187	49.76527469	6.72079E-91	0.018741896	0.020292644	0.018741896	0.020292644
β2	-0.000139868	4.71225E-06	-29.68181785	2.86084E-62	-0.000149185	-0.000130552	-0.000149185	-0.000130552
β3	3.39583E-07	1.53527E-08	22.11882142	1.56166E-47	3.0923E-07	3.69936E-07	3.0923E-07	3.69936E-07

South Texas, Applied to OLOGSS Regions 2:

Regression Statistics	
Multiple R	0.994238324
R Square	0.988509845
Adjusted R Square	0.988263627
Standard Error	0.026795052
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.647535343	2.882511781	4014.781289	1.5764E-135
Residual	140	0.100516472	0.000717975		
Total	143	8.748051814			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.320349357	0.009004856	35.57517997	5.36201E-72	0.302546274	0.33815244	0.302546274	0.33815244
β1	0.019534419	0.000397398	49.15583863	3.4382E-90	0.018748742	0.020320096	0.018748742	0.020320096
β2	-0.000140302	4.77487E-06	-29.38344709	9.69188E-62	-0.000149742	-0.000130862	-0.000149742	-0.000130862
β3	3.41163E-07	1.55567E-08	21.9303828	3.96368E-47	3.10407E-07	3.7192E-07	3.10407E-07	3.7192E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994150147
R Square	0.988334515
Adjusted R Square	0.98808454
Standard Error	0.026852947
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.552894405	2.850964802	3953.738464	4.5499E-135
Residual	140	0.100951309	0.000721081		
Total	143	8.653845713			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.322462264	0.009024312	35.73261409	3.07114E-72	0.304620715	0.340303814	0.304620715	0.340303814
β1	0.019485751	0.000398256	48.9276546	6.36471E-90	0.018698377	0.020273125	0.018698377	0.020273125
β2	-0.000140187	4.78518E-06	-29.29612329	1.3875E-61	-0.000149648	-0.000130727	-0.000149648	-0.000130727
β3	3.41143E-07	1.55903E-08	21.88177944	5.04366E-47	3.1032E-07	3.71966E-07	3.1032E-07	3.71966E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.99407047
R Square	0.988176099
Adjusted R Square	0.98792273
Standard Error	0.026915882
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.476544403	2.825514801	3900.141282	1.1696E-134
Residual	140	0.101425062	0.000724465		
Total	143	8.577969465			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.324216701	0.009045462	35.84302113	2.08007E-72	0.306333337	0.342100066	0.306333337	0.342100066
β1	0.019446254	0.00039919	48.71430741	1.1346E-89	0.018657034	0.020235473	0.018657034	0.020235473
β2	-0.000140099	4.7964E-06	-29.20929598	1.98384E-61	-0.000149582	-0.000130617	-0.000149582	-0.000130617
β3	3.41157E-07	1.56268E-08	21.8315363	6.47229E-47	3.10262E-07	3.72052E-07	3.10262E-07	3.72052E-07

West Coast, Applied to OLOGSS Regions 6:

Regression Statistics	
Multiple R	0.994533252
R Square	0.98909639
Adjusted R Square	0.988862741
Standard Error	0.026511278
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.92601569	2.975338563	4233.261276	4.0262E-137
Residual	140	0.098398698	0.000702848		
Total	143	9.024414388			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.314154129	0.008909489	35.26062149	1.64245E-71	0.296539591	0.331768668	0.296539591	0.331768668
β1	0.019671366	0.000393189	50.03029541	3.32321E-91	0.01889401	0.020448722	0.01889401	0.020448722
β2	-0.000140565	4.7243E-06	-29.75371308	2.13494E-62	-0.000149906	-0.000131225	-0.000149906	-0.000131225
β3	3.40966E-07	1.53919E-08	22.15229024	1.32417E-47	3.10535E-07	3.71397E-07	3.10535E-07	3.71397E-07

Primary Workover Costs

Primary workover costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Workover costs consist of the total of workover rig services, remedial services, equipment repair and other costs. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \qquad (2.B\text{-}6)$$

where Cost = WRK_W

β0 = WRKK

β1 = WRKA

β2 = WRKB

β3 = WRKC

from equation 2-22 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.9839
R Square	0.9681
Adjusted R Square	0.9363
Standard Error	1,034.20
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	32,508,694.98	32,508,694.98	30.39	0.11
Residual	1	1,069,571.02	1,069,571.02		
Total	2	33,578,265.99			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	1,736.081	1,266.632	1.371	0.401	-14,357.935	17,830.097	-14,357.935	17,830.097
β1	1.320	0.239	5.513	0.114	-1.722	4.361	-1.722	4.361

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.7558
R Square	0.5713
Adjusted R Square	0.4284
Standard Error	978.19
Observations	5

ANOVA

	df	SS	MS	F	Significance F
Regression	1	3,824,956.55	3,824,956.55	4.00	0.14
Residual	3	2,870,570.06	956,856.69		
Total	4	6,695,526.61			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	1,949.479	1,043.913	1.867	0.159	-1,372.720	5,271.678	-1,372.720	5,271.678
β1	0.364	0.182	1.999	0.139	-0.216	0.945	-0.216	0.945

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.9762
R Square	0.9530
Adjusted R Square	0.9060
Standard Error	2,405.79
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	117,342,912.53	117,342,912.53	20.27	0.14
Residual	1	5,787,839.96	5,787,839.96		
Total	2	123,130,752.49			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	-2,738.051	2,946.483	-0.929	0.523	-40,176.502	34,700.400	-40,176.502	34,700.400
β1	2.507	0.557	4.503	0.139	-4.568	9.582	-4.568	9.582

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.9898
R Square	0.9798
Adjusted R Square	0.9595
Standard Error	747.71
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	27,074,389.00	27,074,389.00	48.43	0.09
Residual	1	559,069.20	559,069.20		
Total	2	27,633,458.19			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	389.821	915.753	0.426	0.744	-11,245.876	12,025.518	-11,245.876	12,025.518
β1	1.204	0.173	6.959	0.091	-0.995	3.403	-0.995	3.403

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.9985
R Square	0.9969
Adjusted R Square	0.9939
Standard Error	273.2
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	24,387,852.65	24,387,852.65	326.67	0.04
Residual	1	74,656.68	74,656.68		
Total	2	24,462,509.32			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	1,326.648	334.642	3.964	0.157	-2,925.359	5,578.654	-2,925.359	5,578.654
β1	1.143	0.063	18.074	0.035	0.339	1.947	0.339	1.947

Primary Workover Costs - Cost Adjustment Factor

The cost adjustment factor for primary workover costs was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994400682
R Square	0.988832717
Adjusted R Square	0.988593418
Standard Error	0.02694729
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.001886791	3.00062893	4132.207262	2.1441E-136
Residual	140	0.101661902	0.000726156		
Total	143	9.103548693			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312539579	0.009056017	34.51181296	2.43715E-70	0.294635346	0.330443812	0.294635346	0.330443812
β1	0.019707131	0.000399656	49.31028624	2.26953E-90	0.018916991	0.020497272	0.018916991	0.020497272
β2	-0.000140623	4.802E-06	-29.28428914	1.45673E-61	-0.000150117	-0.000131129	-0.000150117	-0.000131129
β3	3.40873E-07	1.5645E-08	21.78791181	8.03921E-47	3.09942E-07	3.71804E-07	3.09942E-07	3.71804E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994469633
R Square	0.98896985
Adjusted R Square	0.98873349
Standard Error	0.026569939
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.861572267	2.953857422	4184.161269	9.0291E-137
Residual	140	0.098834632	0.000705962		
Total	143	8.960406899			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.315903453	0.008929203	35.37868321	1.07799E-71	0.298249938	0.333556967	0.298249938	0.333556967
β1	0.019629392	0.000394059	49.81332121	5.91373E-91	0.018850316	0.020408468	0.018850316	0.020408468
β2	-0.000140391	4.73475E-06	-29.65123432	3.24065E-62	-0.000149752	-0.00013103	-0.000149752	-0.00013103
β3	3.40702E-07	1.5426E-08	22.08625878	1.83379E-47	3.10204E-07	3.712E-07	3.10204E-07	3.712E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994481853
R Square	0.988994155
Adjusted R Square	0.988758316
Standard Error	0.026752366
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.003736634	3.001245545	4193.504662	7.7373E-137
Residual	140	0.100196473	0.000715689		
Total	143	9.103933107			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312750341	0.00899051	34.78671677	9.00562E-71	0.294975619	0.330525063	0.294975619	0.330525063
β1	0.019699787	0.000396765	49.6510621	9.11345E-91	0.018915362	0.020484212	0.018915362	0.020484212
β2	-0.000140541	4.76726E-06	-29.480463	6.51147E-62	-0.000149966	-0.000131116	-0.000149966	-0.000131116
β3	3.40661E-07	1.55319E-08	21.93302302	3.91217E-47	3.09954E-07	3.71368E-07	3.09954E-07	3.71368E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.949969362
R Square	0.902441789
Adjusted R Square	0.900351256
Standard Error	0.090634678
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.63829925	3.546099748	431.6802228	1.59892E-70
Residual	140	1.150050289	0.008214645		
Total	143	11.78834953			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.281549378	0.030459064	9.243533578	3.55063E-16	0.221330174	0.341768582	0.221330174	0.341768582
β1	0.020360006	0.001344204	15.14651492	2.70699E-31	0.017702443	0.02301757	0.017702443	0.02301757
β2	-0.000140998	1.61511E-05	-8.729925387	6.86299E-15	-0.000172929	-0.000109066	-0.000172929	-0.000109066
β3	3.36972E-07	5.26206E-08	6.403797584	2.14112E-09	2.32938E-07	4.41006E-07	2.32938E-07	4.41006E-07

West Coast, Applied to OLOGSS Regions 6:

Regression Statistics	
Multiple R	0.994382746
R Square	0.988797046
Adjusted R Square	0.988556983
Standard Error	0.026729324
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.828330392	2.942776797	4118.9013	2.6803E-136
Residual	140	0.100023944	0.000714457		
Total	143	8.928354335			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.316566704	0.008982767	35.24155917	1.75819E-71	0.298807292	0.334326116	0.298807292	0.334326116
β1	0.019613748	0.000396423	49.47682536	1.45204E-90	0.018829998	0.020397497	0.018829998	0.020397497
β2	-0.000140368	4.76315E-06	-29.46957335	6.80842E-62	-0.000149785	-0.000130951	-0.000149785	-0.000130951
β3	3.40752E-07	1.55185E-08	21.95777375	3.46083E-47	3.10071E-07	3.71433E-07	3.10071E-07	3.71433E-07

Cost to Convert a Primary to Secondary Well

The cost to convert a primary to secondary well was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Conversion costs for a primary to a secondary well consist of pumping equipment, rods and pumps, and supply wells. The data was analyzed on a regional level. The secondary operations costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}7)$$

where Cost = PSW_W
β0 = PSWK
β1 = PSWA
β2 = PSWB
β3 = PSWC
from equation 2-35 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.999208
R Square	0.998416
Adjusted R Square	0.996832
Standard Error	9968.98
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	62,643,414,406.49	62,643,414,406.49	630.34	0.03
Residual	1	99,380,639.94	99,380,639.94		
Total	2	62,742,795,046.43			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-115.557	12,209.462	-0.009	0.994	-155,250.815	155,019.701	-155,250.815	155,019.701
β1	57.930	2.307	25.107	0.025	28.612	87.248	28.612	87.248

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.996760
R Square	0.993531
Adjusted R Square	0.991914
Standard Error	16909.05
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	175,651,490,230.16	175,651,490,230.16	614.35	0.00
Residual	4	1,143,664,392.16	285,916,098.04		
Total	5	176,795,154,622.33			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-10,733.7	14,643.670	-0.733	0.504	-51,391.169	29,923.692	-51,391.169	29,923.692
β1	68.593	2.767	24.786	0.000	60.909	76.276	60.909	76.276

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.999830
R Square	0.999660
Adjusted R Square	0.999320
Standard Error	4047.64
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	48,164,743,341	48,164,743,341	2,939.86	0.01
Residual	1	16,383,350	16,383,350		
Total	2	48,181,126,691			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	-32,919.3	4,957.320	-6.641	0.095	-95,907.768	30,069.148	-95,907.768	30,069.148
β1	50.796	0.937	54.220	0.012	38.893	62.700	38.893	62.700

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	1.00000
R Square	0.99999
Adjusted R Square	0.99999
Standard Error	552.23
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	44,056,261,873.48	44,056,261,873.48	144,469.3	0.00
Residual	1	304,952.52	304,952.52		
Total	2	44,056,566,825.99			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	-25,175.8	676.335	-37.224	0.017	-33,769.389	-16,582.166	-33,769.389	-16,582.166
β1	48.581	0.128	380.091	0.002	46.957	50.205	46.957	50.205

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.999970
R Square	0.999941
Adjusted R Square	0.999882
Standard Error	2317.03
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	90,641,249,203.56	90,641,249,203.56	16,883.5	0.00
Residual	1	5,368,613.99	5,368,613.99		
Total	2	90,646,617,817.55			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	-47,775.5	2,837.767	-16.836	0.038	-83,832.597	-11,718.412	-83,832.597	-11,718.412
β1	69.683	0.536	129.937	0.005	62.869	76.498	62.869	76.498

Cost to Convert a Primary to Secondary Well - Cost Adjustment Factor

The cost adjustment factor for the cost to convert a primary to secondary well was calculated using data through 2008 from the Cost and Indices data base provided EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994210954
R Square	0.988455421
Adjusted R Square	0.988208037
Standard Error	0.032636269
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.7675639	4.255854635	3995.634681	2.1943E-135
Residual	140	0.149117649	0.001065126		
Total	143	12.91668155			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.386844292	0.010967879	35.27065592	1.58464E-71	0.365160206	0.408528378	0.365160206	0.408528378
β1	0.023681158	0.000484029	48.92509151	6.40898E-90	0.022724207	0.024638109	0.022724207	0.024638109
β2	-0.000169861	5.81577E-06	-29.207048	2.00231E-61	-0.00018136	-0.000158363	-0.00018136	-0.000158363
β3	4.12786E-07	1.89479E-08	21.78527316	8.14539E-47	3.75325E-07	4.50247E-07	3.75325E-07	4.50247E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.965088368
R Square	0.931395559
Adjusted R Square	0.929925464
Standard Error	0.077579302
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	11.43935934	3.813119781	633.5614039	3.21194E-81
Residual	140	0.842596733	0.006018548		
Total	143	12.28195608			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.403458143	0.02607162	15.4749932	4.09637E-32	0.351913151	0.455003136	0.351913151	0.455003136
β1	0.023030837	0.00115058	20.01672737	6.5441E-43	0.02075608	0.025305595	0.02075608	0.025305595
β2	-0.000167719	1.38246E-05	-12.13194348	1.34316E-23	-0.000195051	-0.000140387	-0.000195051	-0.000140387
β3	4.10451E-07	4.5041E-08	9.112847285	7.57277E-16	3.21403E-07	4.995E-07	3.21403E-07	4.995E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.930983781
R Square	0.866730801
Adjusted R Square	0.863875032
Standard Error	0.115716747
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.19199867	4.063999556	303.5017657	4.7623E-61
Residual	140	1.874651162	0.013390365		
Total	143	14.06664983			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.39376891	0.038888247	10.12565341	2.02535E-18	0.316884758	0.470653063	0.316884758	0.470653063
β1	0.023409924	0.001716196	13.6405849	1.759E-27	0.020016911	0.026802936	0.020016911	0.026802936
β2	-0.000169013	2.06207E-05	-8.196307608	1.41642E-13	-0.000209782	-0.000128245	-0.000209782	-0.000128245
β3	4.11972E-07	6.71828E-08	6.132113904	8.35519E-09	2.79148E-07	5.44796E-07	2.79148E-07	5.44796E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.930623851
R Square	0.866060752
Adjusted R Square	0.863190626
Standard Error	0.117705607
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.5418858	4.180628599	301.7500036	6.76263E-61
Residual	140	1.939645392	0.01385461		
Total	143	14.48153119			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.363067907	0.039556632	9.178433366	5.17966E-16	0.284862323	0.441273492	0.284862323	0.441273492
β1	0.024133277	0.001745693	13.82446554	5.96478E-28	0.020681947	0.027584606	0.020681947	0.027584606
β2	-0.000175479	2.09751E-05	-8.366057262	5.44112E-14	-0.000216948	-0.00013401	-0.000216948	-0.00013401
β3	4.28328E-07	6.83375E-08	6.267838182	4.24825E-09	2.93221E-07	5.63435E-07	2.93221E-07	5.63435E-07

West Coast, Applied to OLOGSS Regions 6:

Regression Statistics	
Multiple R	0.930187107
R Square	0.865248054
Adjusted R Square	0.862360512
Standard Error	0.116469162
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	12.19426209	4.06475403	299.6486777	1.03233E-60
Residual	140	1.899109212	0.013565066		
Total	143	14.0933713			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.393797507	0.039141107	10.06097011	2.96602E-18	0.316413437	0.471181577	0.316413437	0.471181577
β1	0.023409194	0.001727356	13.55204156	2.96327E-27	0.01999412	0.026824269	0.01999412	0.026824269
β2	-0.000168995	2.07548E-05	-8.142483197	1.91588E-13	-0.000210029	-0.000127962	-0.000210029	-0.000127962
β3	4.11911E-07	6.76196E-08	6.091589926	1.02095E-08	2.78223E-07	5.45599E-07	2.78223E-07	5.45599E-07

Cost to Convert a Producer to an Injector

The cost to convert a production well to an injection well was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Conversion costs for a production to an injection well consist of tubing replacement, distribution lines and header costs. The data was analyzed on a regional level. The secondary operation costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta 0 + \beta 1 * Depth + \beta 2 * Depth^2 + \beta 3 * Depth^3 \quad (2.B\text{-}8)$$

where Cost = PSI_W

β0 = PSIK

β1 = PSIA

β2 = PSIB

β3 = PSIC

from equation 2-36 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.994714
R Square	0.989456
Adjusted R Square	0.978913
Standard Error	3204.94
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	963,939,802.16	963,939,802.16	93.84	0.07
Residual	1	10,271,635.04	10,271,635.04		
Total	2	974,211,437.20			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	11,129.3	3,925.233	2.835	0.216	-38,745.259	61,003.937	-38,745.259	61,003.937
β1	7.186	0.742	9.687	0.065	-2.239	16.611	-2.239	16.611

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.988716
R Square	0.977560
Adjusted R Square	0.971950
Standard Error	4435.41
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3,428,080,322.21	3,428,080,322.21	174.25	0.00
Residual	4	78,691,571.93	19,672,892.98		
Total	5	3,506,771,894.14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	24,640.6	3,841.181	6.415	0.003	13,975.763	35,305.462	13,975.763	35,305.462
β1	9.582	0.726	13.201	0.000	7.567	11.598	7.567	11.598

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.993556
R Square	0.987154
Adjusted R Square	0.974307
Standard Error	3770.13
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,092,230,257.01	1,092,230,257.01	76.84	0.07
Residual	1	14,213,917.83	14,213,917.83		
Total	2	1,106,444,174.85			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	9,356.411	4,617.453	2.026	0.292	-49,313.648	68,026.469	-49,313.648	68,026.469
β1	7.649	0.873	8.766	0.072	-3.438	18.737	-3.438	18.737

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.995436
R Square	0.990893
Adjusted R Square	0.981785
Standard Error	3266.39
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	1,160,837,008.65	1,160,837,008.65	108.80	0.06
Residual	1	10,669,310.85	10,669,310.85		
Total	2	1,171,506,319.50			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	24,054.311	4,000.496	6.013	0.105	-26,776.589	74,885.211	-26,776.589	74,885.211
β1	7.886	0.756	10.431	0.061	-1.720	17.492	-1.720	17.492

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.998023
R Square	0.996050
Adjusted R Square	0.992100
Standard Error	2903.09
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	2,125,305,559.02	2,125,305,559.02	252.17	0.04
Residual	1	8,427,914.12	8,427,914.12		
Total	2	2,133,733,473.15			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	11,125.846	3,555.541	3.129	0.197	-34,051.391	56,303.083	-34,051.391	56,303.083
β1	10.670	0.672	15.880	0.040	2.133	19.208	2.133	19.208

Cost to Convert a Producer to an Injector - Cost Adjustment Factor

The cost adjustment factor for the cost to convert a producer to an injector was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from \$10 to \$200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at \$50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.99432304
R Square	0.988678308
Adjusted R Square	0.9884357
Standard Error	0.026700062
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.715578807	2.905192936	4075.214275	5.6063E-136
Residual	140	0.099805061	0.000712893		
Total	143	8.815383869			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.318906241	0.008972933	35.54091476	6.05506E-72	0.301166271	0.336646211	0.301166271	0.336646211
β1	0.019564167	0.000395989	49.40584281	1.75621E-90	0.018781276	0.020347059	0.018781276	0.020347059
β2	-0.000140323	4.75794E-06	-29.49235038	6.20216E-62	-0.00014973	-0.000130916	-0.00014973	-0.000130916
β3	3.40991E-07	1.55015E-08	21.9972576	2.84657E-47	3.10343E-07	3.71638E-07	3.10343E-07	3.71638E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994644466
R Square	0.989317613
Adjusted R Square	0.989088705
Standard Error	0.025871111
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.678119686	2.892706562	4321.895164	9.5896E-138
Residual	140	0.093704013	0.000669314		
Total	143	8.771823699			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.316208692	0.008694352	36.36943685	3.2883E-73	0.299019491	0.333397893	0.299019491	0.333397893
β1	0.01974618	0.000383695	51.46325116	7.80746E-93	0.018987594	0.020504765	0.018987594	0.020504765
β2	-0.000142963	4.61022E-06	-31.00997536	1.39298E-64	-0.000152077	-0.000133848	-0.000152077	-0.000133848
β3	3.4991E-07	1.50202E-08	23.29589312	5.12956E-50	3.20214E-07	3.79606E-07	3.20214E-07	3.79606E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994321224
R Square	0.988674696
Adjusted R Square	0.988432011
Standard Error	0.026701262
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.713550392	2.904516797	4073.899599	5.7329E-136
Residual	140	0.099814034	0.000712957		
Total	143	8.813364425			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.318954549	0.008973336	35.54470092	5.97425E-72	0.301213782	0.336695317	0.301213782	0.336695317
β1	0.019563077	0.000396007	49.40087012	1.77978E-90	0.018780151	0.020346004	0.018780151	0.020346004
β2	-0.000140319	4.75815E-06	-29.49027089	6.25518E-62	-0.000149726	-0.000130912	-0.000149726	-0.000130912
β3	3.40985E-07	1.55022E-08	21.99592439	2.8654E-47	3.10337E-07	3.71634E-07	3.10337E-07	3.71634E-07

West Texas, Applied to OLOGSS Regions 4:

Regression Statistics	
Multiple R	0.994322163
R Square	0.988676564
Adjusted R Square	0.988433919
Standard Error	0.026700311
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.714383869	2.904794623	4074.579587	5.667E-136
Residual	140	0.099806922	0.000712907		
Total	143	8.814190792			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.318944377	0.008973016	35.54483358	5.97144E-72	0.301204242	0.336684512	0.301204242	0.336684512
β1	0.019563226	0.000395993	49.40300666	1.76961E-90	0.018780328	0.020346125	0.018780328	0.020346125
β2	-0.000140317	4.75798E-06	-29.49085218	6.24031E-62	-0.000149724	-0.00013091	-0.000149724	-0.00013091
β3	3.40976E-07	1.55017E-08	21.99610109	2.8629E-47	3.10328E-07	3.71624E-07	3.10328E-07	3.71624E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.994041278
R Square	0.988118061
Adjusted R Square	0.987863448
Standard Error	0.027307293
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.681741816	2.893913939	3880.863048	1.6477E-134
Residual	140	0.104396354	0.000745688		
Total	143	8.78613817			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.31978359	0.009177001	34.84619603	7.26644E-71	0.301640166	0.337927015	0.301640166	0.337927015
β1	0.019531533	0.000404995	48.22662865	4.2897E-89	0.018730837	0.02033223	0.018730837	0.02033223
β2	-0.000140299	4.86615E-06	-28.83170535	9.47626E-61	-0.00014992	-0.000130679	-0.00014992	-0.000130679
β3	3.41616E-07	1.58541E-08	21.54755837	2.66581E-46	3.10272E-07	3.7296E-07	3.10272E-07	3.7296E-07

Facilities Upgrade Costs for Crude Oil Wells

The facilities upgrading cost for secondary oil wells was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Facilities costs for a secondary oil well consist of plant costs and electrical costs. The data was analyzed on a regional level. The secondary operation costs for each region are determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta 0 + \beta 1 * Depth + \beta 2 * Depth^2 + \beta 3 * Depth^3 \qquad (2.B\text{-}9)$$

where Cost = FAC_W

β0 = FACUPK

β1 = FACUPA

β2 = FACUPB

β3 = FACUPC

from equation 2-23 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.947660
R Square	0.898060
Adjusted R Square	0.796120
Standard Error	6332.38
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	353,260,332.81	353,260,332.81	8.81	0.21
Residual	1	40,099,063.51	40,099,063.51		
Total	2	393,359,396.32			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	20,711.761	7,755.553	2.671	0.228	-77,831.455	119,254.977	-77,831.455	119,254.977
β1	4.350	1.466	2.968	0.207	-14.273	22.973	-14.273	22.973

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.942744
R Square	0.888767
Adjusted R Square	0.851689
Standard Error	6699.62
Observations	5

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,075,905,796.72	1,075,905,796.72	23.97	0.02
Residual	3	134,654,629.89	44,884,876.63		
Total	4	1,210,560,426.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	33,665.6	7,149.747	4.709	0.018	10,911.921	56,419.338	10,911.921	56,419.338
β1	6.112	1.248	4.896	0.016	2.139	10.085	2.139	10.085

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.950784
R Square	0.903990
Adjusted R Square	0.807980
Standard Error	6705.31
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	423,335,427.35	423,335,427.35	9.42	0.20
Residual	1	44,961,183.70	44,961,183.70		
Total	2	468,296,611.04			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	19,032.550	8,212.294	2.318	0.259	-85,314.094	123,379.194	-85,314.094	123,379.194
β1	4.762	1.552	3.068	0.201	-14.957	24.482	-14.957	24.482

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.90132
R Square	0.81238
Adjusted R Square	0.62476
Standard Error	8,531
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	315,132,483.91	315,132,483.91	4.33	0.29
Residual	1	72,780,134.04	72,780,134.04		
Total	2	387,912,617.95			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	37,322	10,448.454	3.572	0.174	-95,437.589	170,081.677	-95,437.589	170,081.677
β1	4.109	1.975	2.081	0.285	-20.980	29.198	-20.980	29.198

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.974616
R Square	0.949876
Adjusted R Square	0.899753
Standard Error	6,765.5
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	867,401,274.79	867,401,274.79	18.95	0.14
Residual	1	45,771,551.83	45,771,551.83		
Total	2	913,172,826.62			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	23,746.6	8,285.972	2.866	0.214	-81,536.251	129,029.354	-81,536.251	129,029.354
β1	6.817	1.566	4.353	0.144	-13.080	26.713	-13.080	26.713

Facilities Upgrade Costs for Oil Wells - Cost Adjustment Factor

The cost adjustment factor for facilities upgrade costs for oil wells was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994217662
R Square	0.988468759
Adjusted R Square	0.988221661
Standard Error	0.026793237
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.615198936	2.871732979	4000.310244	2.0238E-135
Residual	140	0.100502859	0.000717878		
Total	143	8.715701795			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.321111529	0.009004246	35.66223488	3.93903E-72	0.303309651	0.338913406	0.303309651	0.338913406
β1	0.019515262	0.000397371	49.11095778	3.88014E-90	0.018729638	0.020300885	0.018729638	0.020300885
β2	-0.00014023	4.77454E-06	-29.37035185	1.02272E-61	-0.00014967	-0.00013079	-0.00014967	-0.00013079
β3	3.4105E-07	1.55556E-08	21.92459665	4.07897E-47	3.10296E-07	3.71805E-07	3.10296E-07	3.71805E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994217643
R Square	0.988468723
Adjusted R Square	0.988221624
Standard Error	0.026793755
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.615504692	2.871834897	4000.297521	2.0242E-135
Residual	140	0.100506746	0.000717905		
Total	143	8.716011438			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.321091731	0.00900442	35.65934676	3.9795E-72	0.30328951	0.338893953	0.30328951	0.338893953
β1	0.019515756	0.000397379	49.11125155	3.87707E-90	0.018730117	0.020301395	0.018730117	0.020301395
β2	-0.000140234	4.77464E-06	-29.37065243	1.02145E-61	-0.000149674	-0.000130794	-0.000149674	-0.000130794
β3	3.41061E-07	1.55559E-08	21.92486379	4.07357E-47	3.10306E-07	3.71816E-07	3.10306E-07	3.71816E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994881087
R Square	0.989788377
Adjusted R Square	0.989569556
Standard Error	0.025598703
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.892246941	2.964082314	4523.289171	4.0903E-139
Residual	140	0.0917411	0.000655294		
Total	143	8.983988041			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.305413562	0.008602806	35.50162345	6.96151E-72	0.288405354	0.32242177	0.288405354	0.32242177
β1	0.019922983	0.000379655	52.47659224	5.82045E-94	0.019172385	0.020673581	0.019172385	0.020673581
β2	-0.000143398	4.56168E-06	-31.43544891	2.62249E-65	-0.000152417	-0.00013438	-0.000152417	-0.00013438
β3	3.48664E-07	1.48621E-08	23.45993713	2.3433E-50	3.1928E-07	3.78047E-07	3.1928E-07	3.78047E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994218671
R Square	0.988470767
Adjusted R Square	0.988223712
Standard Error	0.026793398
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.616820316	2.872273439	4001.015021	1.9993E-135
Residual	140	0.100504067	0.000717886		
Total	143	8.717324383			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.32105584	0.0090043	35.65583598	4.02926E-72	0.303253856	0.338857825	0.303253856	0.338857825
β1	0.019516684	0.000397373	49.11424236	3.84594E-90	0.018731056	0.020302312	0.018731056	0.020302312
β2	-0.00014024	4.77457E-06	-29.37236101	1.01431E-61	-0.00014968	-0.000130801	-0.00014968	-0.000130801
β3	3.4108E-07	1.55557E-08	21.92639924	4.0427E-47	3.10326E-07	3.71835E-07	3.10326E-07	3.71835E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.994682968
R Square	0.989394207
Adjusted R Square	0.98916694
Standard Error	0.025883453
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.749810675	2.916603558	4353.444193	5.7951E-138
Residual	140	0.093793438	0.000669953		
Total	143	8.843604113			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.320979436	0.0086985	36.90055074	5.22609E-74	0.303782034	0.338176837	0.303782034	0.338176837
β1	0.019117244	0.000383878	49.80033838	6.12166E-91	0.018358297	0.019876191	0.018358297	0.019876191
β2	-0.000134273	4.61242E-06	-29.11109331	2.97526E-61	-0.000143392	-0.000125154	-0.000143392	-0.000125154
β3	3.21003E-07	1.50274E-08	21.36117616	6.78747E-46	2.91293E-07	3.50713E-07	2.91293E-07	3.50713E-07

Natural Gas Well Facilities Costs

Natural gas well facilities costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Well facilities costs consist of flowlines and connections, production package costs, and storage tank costs. The data was analyzed on a regional level. The independent variables are depth and Q, which is the flow rate of natural gas in million cubic feet. The form of the equation is given below:

$$Cost = \beta 0 + \beta 1 * Depth + \beta 2 * Q + \beta 3 * Depth * Q \qquad (2.B\text{-}10)$$

where Cost = FWC_W
β0 = FACGK
β1 = FACGA
β2 = FACGB
β3 = FACGC
Q = PEAKDAILY_RATE
from equation 2-28 in Chapter 2.

Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9834
R Square	0.9672
Adjusted R Square	0.9562
Standard Error	5,820.26
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8,982,542,532.41	2,994,180,844.14	88.39	0.00
Residual	9	304,879,039.45	33,875,448.83		
Total	12	9,287,421,571.86			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,477.41	4,694.03	0.74	0.48	-7,141.24	14,096.05	-7,141.24	14,096.05
β1	5.04	0.40	12.51	0.00	4.13	5.95	4.13	5.95
β2	63.87	19.07	3.35	0.01	20.72	107.02	20.72	107.02
β3	0.00	0.00	-3.18	0.01	-0.01	0.00	-0.01	0.00

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.9621
R Square	0.9256
Adjusted R Square	0.9139
Standard Error	8,279.60
Observations	23

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	16,213,052,116.02	5,404,350,705.34	78.84	0.00
Residual	19	1,302,484,315.70	68,551,806.09		
Total	22	17,515,536,431.72			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	14,960.60	4,066.98	3.68	0.00	6,448.31	23,472.90	6,448.31	23,472.90
β1	4.87	0.47	10.34	0.00	3.88	5.85	3.88	5.85
β2	28.49	6.42	4.43	0.00	15.04	41.93	15.04	41.93
β3	0.00	0.00	-3.62	0.00	0.00	0.00	0.00	0.00

Mid-Continent, applied to OLOGSS regions 3 and 6:

Regression Statistics	
Multiple R	0.9917
R Square	0.9835
Adjusted R Square	0.9765
Standard Error	4,030.43
Observations	11

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	6,796,663,629.62	2,265,554,543.21	139.47	0.00
Residual	7	113,710,456.60	16,244,350.94		
Total	10	6,910,374,086.22			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	10,185.92	3,441.41	2.96	0.02	2,048.29	18,323.54	2,048.29	18,323.54
β1	4.51	0.29	15.71	0.00	3.83	5.18	3.83	5.18
β2	55.38	14.05	3.94	0.01	22.16	88.60	22.16	88.60
β3	0.00	0.00	-3.78	0.01	-0.01	0.00	-0.01	0.00

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9594
R Square	0.9204
Adjusted R Square	0.8806
Standard Error	7,894.95
Observations	10

ANOVA

	df	SS	MS	F	Significance F
Regression	3	4,322,988,996.06	1,440,996,332.02	23.12	0.00
Residual	6	373,981,660.54	62,330,276.76		
Total	9	4,696,970,656.60			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	7,922.48	8,200.06	0.97	0.37	-12,142.36	27,987.31	-12,142.36	27,987.31
β1	6.51	1.14	5.71	0.00	3.72	9.30	3.72	9.30
β2	89.26	28.88	3.09	0.02	18.59	159.94	18.59	159.94
β3	-0.01	0.00	-2.77	0.03	-0.01	0.00	-0.01	0.00

Gas Well Facilities Costs - Cost Adjustment Factor

The cost adjustment factor for gas well facilities cost was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $1 to $20 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $5 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Gas Price} + \beta2 * \text{Gas Price}^2 + \beta3 * \text{Gas Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.995733794
R Square	0.991485789
Adjusted R Square	0.991303341
Standard Error	0.025214281
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	10.3648558	3.454951933	5434.365566	1.2179E-144
Residual	140	0.089006392	0.00063576		
Total	143	10.45386219			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.276309237	0.008473615	32.60818851	2.86747E-67	0.259556445	0.293062029	0.259556445	0.293062029
β1	0.20599743	0.003739533	55.08640551	8.89871E-97	0.198604173	0.213390688	0.198604173	0.213390688
β2	-0.014457925	0.000449317	-32.17753015	1.48375E-66	-0.015346249	-0.0135696	-0.015346249	-0.0135696
β3	0.000347281	1.46389E-05	23.72318475	6.71084E-51	0.000318339	0.000376223	0.000318339	0.000376223

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.99551629
R Square	0.991052684
Adjusted R Square	0.990860956
Standard Error	0.025683748
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.22936837	3.409789455	5169.05027	3.9254E-143
Residual	140	0.092351689	0.000659655		
Total	143	10.32172006			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.280854163	0.008631386	32.5387085	3.73403E-67	0.263789449	0.297918878	0.263789449	0.297918878
β1	0.204879431	0.00380916	53.78599024	2.17161E-95	0.197348518	0.212410345	0.197348518	0.212410345
β2	-0.014391989	0.000457683	-31.44530093	2.52353E-65	-0.015296854	-0.013487125	-0.015296854	-0.013487125
β3	0.000345909	1.49115E-05	23.19753012	8.21832E-50	0.000316428	0.00037539	0.000316428	0.00037539

Mid-Continent, Applied to OLOGSS Regions 3 and 6:

Regression Statistics	
Multiple R	0.995511275
R Square	0.991042698
Adjusted R Square	0.990850756
Standard Error	0.025690919
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.22356717	3.407855722	5163.235345	4.2442E-143
Residual	140	0.092403264	0.000660023		
Total	143	10.31597043			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.280965064	0.008633796	32.5424714	3.68097E-67	0.263895586	0.298034543	0.263895586	0.298034543
β1	0.204856879	0.003810223	53.7650588	2.28751E-95	0.197323863	0.212389895	0.197323863	0.212389895
β2	-0.014391983	0.000457811	-31.43650889	2.61165E-65	-0.0152971	-0.013486865	-0.0152971	-0.013486865
β3	0.000345929	1.49156E-05	23.19242282	8.42221E-50	0.00031644	0.000375418	0.00031644	0.000375418

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.995452965
R Square	0.990926606
Adjusted R Square	0.990732176
Standard Error	0.025768075
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.15228252	3.384094173	5096.576002	1.0453E-142
Residual	140	0.092959113	0.000663994		
Total	143	10.24524163			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.282511839	0.008659725	32.62364879	2.704E-67	0.265391097	0.299632581	0.265391097	0.299632581
β1	0.204502598	0.003821666	53.51137044	4.3021E-95	0.196946958	0.212058237	0.196946958	0.212058237
β2	-0.014382652	0.000459186	-31.32206064	4.08566E-65	-0.015290487	-0.013474816	-0.015290487	-0.013474816
β3	0.000345898	1.49604E-05	23.12086258	1.18766E-49	0.00031632	0.000375475	0.00031632	0.000375475

Fixed Annual Costs for Crude Oil Wells

The fixed annual cost for crude oil wells was calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Fixed annual costs consist of supervision and overhead costs, auto usage costs, operative supplies, labor costs, supplies and services costs, equipment usage and other costs.

The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta 0 + \beta 1 * Depth + \beta 2 * Depth^2 + \beta 3 * Depth^3 \qquad (2.B\text{-}11)$$

where Cost = OMO_W
β0 = OMOK
β1 = OMOA
β2 = OMOB
β3 = OMOC
from equation 2-30 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9895
R Square	0.9792
Adjusted R Square	0.9584
Standard Error	165.6
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,290,021.8	1,290,021.8	47.0	0.1
Residual	1	27,419.5	27,419.5		
Total	2	1,317,441.3			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	6,026.949	202.804	29.718	0.021	3,450.097	8,603.802	3,450.097	8,603.802
β1	0.263	0.038	6.859	0.092	-0.224	0.750	-0.224	0.750

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.8631
R Square	0.7449
Adjusted R Square	0.6811
Standard Error	2,759.2
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	88,902,026.9	88,902,026.9	11.7	0.0
Residual	4	30,452,068.1	7,613,017.0		
Total	5	119,354,095.0			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	7,171.358	2,389.511	3.001	0.040	536.998	13,805.718	536.998	13,805.718
β1	1.543	0.452	3.417	0.027	0.289	2.797	0.289	2.797

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9888
R Square	0.9777
Adjusted R Square	0.9554
Standard Error	325.8
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4,654,650.4	4,654,650.4	43.9	0.1
Residual	1	106,147.3	106,147.3		
Total	2	4,760,797.7			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	5,572.283	399.025	13.965	0.046	502.211	10,642.355	502.211	10,642.355
β1	0.499	0.075	6.622	0.095	-0.459	1.458	-0.459	1.458

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.9634
R Square	0.9282
Adjusted R Square	0.8923
Standard Error	455.6
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5,368,949.5	5,368,949.5	25.9	0.0
Residual	2	415,138.5	207,569.2		
Total	3	5,784,088.0			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	6,327.733	447.809	14.130	0.005	4,400.964	8,254.501	4,400.964	8,254.501
β1	0.302	0.059	5.086	0.037	0.046	0.557	0.046	0.557

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9908
R Square	0.9817
Adjusted R Square	0.9725
Standard Error	313.1
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	10,498,366.6	10,498,366.6	107.1	0.0
Residual	2	196,056.3	98,028.2		
Total	3	10,694,422.9			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	5,193.399	307.742	16.876	0.003	3,869.291	6,517.508	3,869.291	6,517.508
β1	0.422	0.041	10.349	0.009	0.246	0.597	0.246	0.597

Fixed Annual Costs for Oil Wells - Cost Adjustment Factor

The cost adjustment factor of the fixed annual cost for oil wells was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994014283
R Square	0.988064394
Adjusted R Square	0.987808631
Standard Error	0.026960479
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.424110153	2.808036718	3863.203308	2.2587E-134
Residual	140	0.101761442	0.000726867		
Total	143	8.525871595			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.325522735	0.00906045	35.9278779	1.54278E-72	0.30760974	0.343435731	0.30760974	0.343435731
β1	0.019415379	0.000399851	48.55651174	1.74247E-89	0.018624852	0.020205906	0.018624852	0.020205906
β2	-0.000139999	4.80435E-06	-29.14014276	2.63883E-61	-0.000149498	-0.000130501	-0.000149498	-0.000130501
β3	3.41059E-07	1.56527E-08	21.78917295	7.98896E-47	3.10113E-07	3.72006E-07	3.10113E-07	3.72006E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.972995979
R Square	0.946721175
Adjusted R Square	0.945579485
Standard Error	0.052710031
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	6.91165462	2.303884873	829.2285185	6.67464E-89
Residual	140	0.388968632	0.002778347		
Total	143	7.300623252			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.305890757	0.01771395	17.26835352	1.6689E-36	0.270869326	0.340912188	0.270869326	0.340912188
β1	0.019637228	0.000781743	25.11979642	1.01374E-53	0.01809168	0.021182776	0.01809168	0.021182776
β2	-0.000147609	9.39291E-06	-15.71490525	1.03843E-32	-0.000166179	-0.000129038	-0.000166179	-0.000129038
β3	3.60127E-07	3.06024E-08	11.76795581	1.17387E-22	2.99625E-07	4.2063E-07	2.99625E-07	4.2063E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.993998856
R Square	0.988033725
Adjusted R Square	0.987777305
Standard Error	0.02698784
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.419321124	2.806440375	3853.182417	2.7032E-134
Residual	140	0.10196809	0.000728344		
Total	143	8.521289214			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.32545185	0.009069645	35.88363815	1.80273E-72	0.307520675	0.343383025	0.307520675	0.343383025
β1	0.019419103	0.000400257	48.51658921	1.94263E-89	0.018627774	0.020210433	0.018627774	0.020210433
β2	-0.000140059	4.80922E-06	-29.12303298	2.83205E-61	-0.000149567	-0.000130551	-0.000149567	-0.000130551
β3	3.41232E-07	1.56686E-08	21.77807458	8.44228E-47	3.10254E-07	3.72209E-07	3.10254E-07	3.72209E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.977862049
R Square	0.956214186
Adjusted R Square	0.955275919
Standard Error	0.050111949
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	7.677722068	2.559240689	1019.127536	7.26235E-95
Residual	140	0.351569047	0.002511207		
Total	143	8.029291115			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.343679311	0.016840828	20.40750634	8.67459E-44	0.310384089	0.376974533	0.310384089	0.376974533
β1	0.020087054	0.000743211	27.02739293	2.04852E-57	0.018617686	0.021556422	0.018617686	0.021556422
β2	-0.000153877	8.92993E-06	-17.23164844	2.04504E-36	-0.000171532	-0.000136222	-0.000171532	-0.000136222
β3	3.91397E-07	2.9094E-08	13.45286338	5.31787E-27	3.33877E-07	4.48918E-07	3.33877E-07	4.48918E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.993729589
R Square	0.987498496
Adjusted R Square	0.987230606
Standard Error	0.027203598
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.183798235	2.727932745	3686.217436	5.7808E-133
Residual	140	0.103605007	0.000740036		
Total	143	8.287403242			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.330961672	0.009142153	36.20171926	5.90451E-73	0.312887144	0.3490362	0.312887144	0.3490362
β1	0.019295414	0.000403457	47.82521879	1.29343E-88	0.018497758	0.02009307	0.018497758	0.02009307
β2	-0.000139784	4.84767E-06	-28.83529781	9.33567E-61	-0.000149368	-0.0001302	-0.000149368	-0.0001302
β3	3.4128E-07	1.57939E-08	21.60840729	1.96666E-46	3.10055E-07	3.72505E-07	3.10055E-07	3.72505E-07

Fixed Annual Costs for Natural Gas Wells

Fixed annual costs for natural gas wells were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Fixed annual costs consist of the lease equipment costs for natural gas production for a given year. The data was analyzed on a regional level. The independent variables are depth and Q which is the flow rate of natural gas in million cubic feet. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Q + \beta3 * Depth * Q \tag{2.B-12}$$

where Cost = FOAMG_W
β0 = OMGK
β1 = OMGA
β2 = OMGB
β3 = OMGC
Q = PEAKDAILY_RATE
from equation 2-29 in Chapter 2.

Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.928
R Square	0.861
Adjusted R Square	0.815
Standard Error	6,471.68
Observations	13

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	2,344,632,468.49	781,544,156.16	18.66	0.00
Residual	9	376,944,241.62	41,882,693.51		
Total	12	2,721,576,710.11			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	4,450.28	5,219.40	0.85	0.42	-7,356.84	16,257.40	-7,356.84	16,257.40
β1	2.50	0.45	5.58	0.00	1.49	3.51	1.49	3.51
β2	27.65	21.21	1.30	0.22	-20.33	75.63	-20.33	75.63
β3	0.00	0.00	-1.21	0.26	0.00	0.00	0.00	0.00

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.913
R Square	0.834
Adjusted R Square	0.807
Standard Error	6,564.36
Observations	23

ANOVA

	df	SS	MS	F	Significance F
Regression	3	4,100,685,576.61	1,366,895,192.20	31.72	0.00
Residual	19	818,725,806.73	43,090,831.93		
Total	22	4,919,411,383.34			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	11,145.70	3,224.45	3.46	0.00	4,396.85	17,894.55	4,396.85	17,894.55
β1	2.68	0.37	7.17	0.00	1.90	3.46	1.90	3.46
β2	7.67	5.09	1.51	0.15	-2.99	18.33	-2.99	18.33
β3	0.00	0.00	-1.21	0.24	0.00	0.00	0.00	0.00

Mid-Continent, applied to OLOGSS region 3 and 6:

Regression Statistics	
Multiple R	0.934
R Square	0.873
Adjusted R Square	0.830
Standard Error	6,466.88
Observations	13

ANOVA

	df	SS	MS	F	Significance F
Regression	3	2,578,736,610.45	859,578,870.15	20.55	0.00
Residual	9	376,384,484.71	41,820,498.30		
Total	12	2,955,121,095.16			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	8,193.82	5,410.04	1.51	0.16	-4,044.54	20,432.18	-4,044.54	20,432.18
β1	2.75	0.45	6.14	0.00	1.74	3.77	1.74	3.77
β2	21.21	18.04	1.18	0.27	-19.59	62.01	-19.59	62.01
β3	0.00	0.00	-1.12	0.29	0.00	0.00	0.00	0.00

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	0.945
R Square	0.893
Adjusted R Square	0.840
Standard Error	6,104.84
Observations	10

ANOVA

	df	SS	MS	F	Significance F
Regression	3	1,874,387,985.75	624,795,995.25	16.76	0.00
Residual	6	223,614,591.98	37,269,098.66		
Total	9	2,098,002,577.72			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	7,534.86	6,340.77	1.19	0.28	-7,980.45	23,050.17	-7,980.45	23,050.17
β1	3.81	0.88	4.33	0.00	1.66	5.97	1.66	5.97
β2	32.27	22.33	1.44	0.20	-22.38	86.92	-22.38	86.92
β3	0.00	0.00	-1.18	0.28	-0.01	0.00	-0.01	0.00

Fixed Annual Costs for Gas Wells - Cost Adjustment Factor

The cost adjustment factor of the fixed annual cost for gas wells was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $1 to $20 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $5 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Gas Price} + \beta2 * \text{Gas Price}^2 + \beta3 * \text{Gas Price}^3$$

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.994836789
R Square	0.989700237
Adjusted R Square	0.989479527
Standard Error	0.029019958
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	11.32916798	3.776389326	4484.181718	7.4647E-139
Residual	140	0.117902114	0.000842158		
Total	143	11.44707009			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.234219858	0.009752567	24.01622716	1.68475E-51	0.21493851	0.253501206	0.21493851	0.253501206
β1	0.216761767	0.004303953	50.36340872	1.37772E-91	0.20825262	0.225270914	0.20825262	0.225270914
β2	-0.015234638	0.000517134	-29.45972427	7.08872E-62	-0.01625704	-0.014212235	-0.01625704	-0.014212235
β3	0.000365319	1.68484E-05	21.68270506	1.3574E-46	0.000332009	0.000398629	0.000332009	0.000398629

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.995657421
R Square	0.991333701
Adjusted R Square	0.991147994
Standard Error	0.02551118
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.42258156	3.474193854	5338.176859	4.2055E-144
Residual	140	0.091114842	0.00065082		
Total	143	10.5136964			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.276966489	0.008573392	32.30535588	9.09319E-67	0.260016432	0.293916546	0.260016432	0.293916546
β1	0.205740933	0.003783566	54.37751691	5.03408E-96	0.198260619	0.213221246	0.198260619	0.213221246
β2	-0.014407802	0.000454608	-31.6927929	9.63037E-66	-0.015306587	-0.013509017	-0.015306587	-0.013509017
β3	0.00034576	1.48113E-05	23.34441529	4.06714E-50	0.000316478	0.000375043	0.000316478	0.000375043

Mid-Continent, Applied to OLOGSS Region 3 and 6:

Regression Statistics	
Multiple R	0.995590124
R Square	0.991199695
Adjusted R Square	0.991011117
Standard Error	0.025596313
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.33109303	3.443697678	5256.179662	1.231E-143
Residual	140	0.091723972	0.000655171		
Total	143	10.42281701			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.278704883	0.008602002	32.40000063	6.33409E-67	0.261698262	0.295711504	0.261698262	0.295711504
β1	0.205373482	0.003796192	54.09986358	9.97995E-96	0.197868206	0.212878758	0.197868206	0.212878758
β2	-0.014404563	0.000456125	-31.58028284	1.49116E-65	-0.015306347	-0.013502779	-0.015306347	-0.013502779
β3	0.000345945	1.48607E-05	23.27919988	5.55628E-50	0.000316565	0.000375325	0.000316565	0.000375325

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.995548929
R Square	0.99111767
Adjusted R Square	0.990927334
Standard Error	0.02564864
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	10.27673171	3.425577238	5207.209824	2.3566E-143
Residual	140	0.092099383	0.000657853		
Total	143	10.3688311			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.279731342	0.008619588	32.45298388	5.17523E-67	0.262689954	0.296772729	0.262689954	0.296772729
β1	0.205151971	0.003803953	53.93125949	1.51455E-95	0.197631352	0.21267259	0.197631352	0.21267259
β2	-0.014402579	0.000457058	-31.51151347	1.94912E-65	-0.015306207	-0.013498952	-0.015306207	-0.013498952
β3	0.00034606	1.48911E-05	23.23943141	6.72233E-50	0.00031662	0.000375501	0.00031662	0.000375501

Fixed Annual Costs for Secondary Production

The fixed annual cost for secondary oil production was calculated an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). The data was analyzed on a regional level. The secondary operations costs for each region were determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Depth} + \beta2 * \text{Depth}^2 + \beta3 * \text{Depth}^3 \qquad (2.B\text{-}13)$$

where Cost = OPSEC_W

β0 = OPSECK

β1 = OPSECA

β2 = OPSECB

β3 = OPSECC

from equation 2-31 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9972
R Square	0.9945
Adjusted R Square	0.9890
Standard Error	1,969.67
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	698,746,493.71	698,746,493.71	180.11	0.05
Residual	1	3,879,582.16	3,879,582.16		
Total	2	702,626,075.87			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	30,509.3	2,412.338	12.647	0.050	-142.224	61,160.827	-142.224	61,160.827
β1	6.118	0.456	13.420	0.047	0.326	11.911	0.326	11.911

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.935260
R Square	0.874710
Adjusted R Square	0.843388
Standard Error	8414.07
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,977,068,663.41	1,977,068,663.41	27.93	0.01
Residual	4	283,186,316.21	70,796,579.05		
Total	5	2,260,254,979.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	55,732.7	7,286.799	7.648	0.002	35,501.310	75,964.186	35,501.310	75,964.186
β1	7.277	1.377	5.285	0.006	3.454	11.101	3.454	11.101

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.998942
R Square	0.997884
Adjusted R Square	0.995768
Standard Error	1329.04
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	833,049,989.02	833,049,989.02	471.62	0.03
Residual	1	1,766,354.45	1,766,354.45		
Total	2	834,816,343.47			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	28,208.7	1,627.738	17.330	0.037	7,526.417	48,890.989	7,526.417	48,890.989
β1	6.680	0.308	21.717	0.029	2.772	10.589	2.772	10.589

Rocky Mountains, applied to OLOGSS regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.989924
R Square	0.979949
Adjusted R Square	0.959899
Standard Error	3639.10
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	647,242,187.96	647,242,187.96	48.87	0.09
Residual	1	13,243,073.43	13,243,073.43		
Total	2	660,485,261.39			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	53,857.06	4,456.973	12.084	0.053	-2,773.909	110,488.034	-2,773.909	110,488.034
β1	5.888	0.842	6.991	0.090	-4.814	16.591	-4.814	16.591

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.992089
R Square	0.984240
Adjusted R Square	0.968480
Standard Error	5193.40
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1,684,438,248.88	1,684,438,248.88	62.45	0.08
Residual	1	26,971,430.96	26,971,430.96		
Total	2	1,711,409,679.84			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	35,893.465	6,360.593	5.643	0.112	-44,925.189	116,712.119	-44,925.189	116,712.119
β1	9.499	1.202	7.903	0.080	-5.774	24.773	-5.774	24.773

Fixed Annual Costs for Secondary Production - Cost Adjustment Factor

The cost adjustment factor of the fixed annual costs for secondary production was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Regions 1, 5, and 7:

Regression Statistics	
Multiple R	0.994022382
R Square	0.988080495
Adjusted R Square	0.987825078
Standard Error	0.026956819
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.433336986	2.811112329	3868.484883	2.0551E-134
Residual	140	0.101733815	0.00072667		
Total	143	8.535070802			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.325311813	0.00905922	35.90947329	1.646E-72	0.307401249	0.343222377	0.307401249	0.343222377
β1	0.019419982	0.000399797	48.57461816	1.65866E-89	0.018629562	0.020210402	0.018629562	0.020210402
β2	-0.000140009	4.80369E-06	-29.14604996	2.57525E-61	-0.000149506	-0.000130512	-0.000149506	-0.000130512
β3	3.41057E-07	1.56506E-08	21.79195958	7.87903E-47	3.10115E-07	3.71999E-07	3.10115E-07	3.71999E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.993830992
R Square	0.987700041
Adjusted R Square	0.987436471
Standard Error	0.027165964
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.296590955	2.765530318	3747.383987	1.8532E-133
Residual	140	0.103318541	0.00073799		
Total	143	8.399909496			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.321750317	0.009129506	35.24290662	1.74974E-71	0.303700794	0.33979984	0.303700794	0.33979984
β1	0.019369439	0.000402899	48.0752057	6.49862E-89	0.018572887	0.020165992	0.018572887	0.020165992
β2	-0.000140208	4.84096E-06	-28.96291516	5.49447E-61	-0.000149779	-0.000130638	-0.000149779	-0.000130638
β3	3.42483E-07	1.5772E-08	21.71459435	1.15795E-46	3.11301E-07	3.73665E-07	3.11301E-07	3.73665E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994021683
R Square	0.988079106
Adjusted R Square	0.987823658
Standard Error	0.026959706
Observations	144

ANOVA

	df	SS	MS	F	Significance F
Regression	3	8.43414809	2.811382697	3868.028528	2.0719E-134
Residual	140	0.101755604	0.000726826		
Total	143	8.535903693			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	0.325281756	0.00906019	35.90231108	1.68802E-72	0.307369274	0.343194238	0.307369274	0.343194238
β1	0.019420568	0.00039984	48.57088177	1.67561E-89	0.018630063	0.020211072	0.018630063	0.020211072
β2	-0.000140009	4.80421E-06	-29.14305099	2.60734E-61	-0.000149507	-0.000130511	-0.000149507	-0.000130511
β3	3.41049E-07	1.56523E-08	21.7891193	7.99109E-47	3.10103E-07	3.71994E-07	3.10103E-07	3.71994E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994023418
R Square	0.988082555
Adjusted R Square	0.987827181
Standard Error	0.026956158
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.434398087	2.811466029	3869.161392	2.0304E-134
Residual	140	0.101728825	0.000726634		
Total	143	8.536126912			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.325293493	0.009058998	35.90833165	1.65262E-72	0.307383368	0.343203618	0.307383368	0.343203618
β1	0.019420405	0.000399787	48.57686713	1.64854E-89	0.018630005	0.020210806	0.018630005	0.020210806
β2	-0.000140009	4.80358E-06	-29.14672886	2.56804E-61	-0.000149505	-0.000130512	-0.000149505	-0.000130512
β3	3.41053E-07	1.56502E-08	21.792237	7.86817E-47	3.10111E-07	3.71994E-07	3.10111E-07	3.71994E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.993899019
R Square	0.98783526
Adjusted R Square	0.987574587
Standard Error	0.027222624
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.42499532	2.808331773	3789.557133	8.5487E-134
Residual	140	0.103749972	0.000741071		
Total	143	8.528745292			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.327122709	0.009148547	35.75679345	2.81971E-72	0.30903554	0.345209878	0.30903554	0.345209878
β1	0.019283711	0.000403739	47.76280844	1.53668E-88	0.018485497	0.020081925	0.018485497	0.020081925
β2	-0.000138419	4.85106E-06	-28.53379985	3.28809E-60	-0.00014801	-0.000128828	-0.00014801	-0.000128828
β3	3.36276E-07	1.58049E-08	21.27670912	1.03818E-45	3.05029E-07	3.67523E-07	3.05029E-07	3.67523E-07

Lifting Costs

Lifting costs for crude oil wells were calculated using average an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Lifting costs consist of labor costs for the pumper, chemicals, fuel, power and water costs. The data was analyzed on a regional level. The independent variable is depth. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Depth} + \beta 2 * \text{Depth}^2 + \beta 3 * \text{Depth}^3 \qquad (2.B\text{-}14)$$

where Cost = OML_W

β0 = OMLK

β1 = OMLA

β2 = OMLB

β3 = OMLC

from equation 2-32 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9994
R Square	0.9988
Adjusted R Square	0.9976
Standard Error	136.7
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	15,852,301	15,852,301	849	0
Residual	1	18,681	18,681		
Total	2	15,870,982			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	7,534.515	167.395	45.010	0.014	5,407.565	9,661.465	5,407.565	9,661.465
β1	0.922	0.032	29.131	0.022	0.520	1.323	0.520	1.323

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.8546
R Square	0.7304
Adjusted R Square	0.6764
Standard Error	2263.5
Observations	7

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	69,387,339	69,387,339	14	0
Residual	5	25,617,128	5,123,426		
Total	6	95,004,467			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	11,585.191	1,654.440	7.002	0.001	7,332.324	15,838.058	7,332.324	15,838.058
β1	0.912	0.248	3.680	0.014	0.275	1.549	0.275	1.549

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9997
R Square	0.9995
Adjusted R Square	0.9990
Standard Error	82.0
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	13,261,874	13,261,874	1,972	0
Residual	1	6,726	6,726		
Total	2	13,268,601			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	8,298.339	100.447	82.614	0.008	7,022.045	9,574.634	7,022.045	9,574.634
β1	0.843	0.019	44.403	0.014	0.602	1.084	0.602	1.084

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	1.0000
R Square	1.0000
Adjusted R Square	0.9999
Standard Error	11.5
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	3,979,238	3,979,238	30,138	0
Residual	1	132	132		
Total	2	3,979,370			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	10,137.398	14.073	720.342	0.001	9,958.584	10,316.212	9,958.584	10,316.212
β1	0.462	0.003	173.603	0.004	0.428	0.495	0.428	0.495

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9969
R Square	0.9937
Adjusted R Square	0.9874
Standard Error	1134.3
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	203,349,853	203,349,853	158	0
Residual	1	1,286,583	1,286,583		
Total	2	204,636,436			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	5,147.313	1,389.199	3.705	0.168	-12,504.063	22,798.689	-12,504.063	22,798.689
β1	3.301	0.263	12.572	0.051	-0.035	6.636	-0.035	6.636

Lifting Costs - Cost Adjustment Factor

The cost adjustment factor for lifting costs for was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta 0 + \beta 1 * \text{Oil Price} + \beta 2 * \text{Oil Price}^2 + \beta 3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.994419415
R Square	0.988869972
Adjusted R Square	0.988631472
Standard Error	0.026749137
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.900010642	2.966670214	4146.195026	1.6969E-136
Residual	140	0.100172285	0.000715516		
Total	143	9.000182927			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.314447949	0.008989425	34.97976138	4.49274E-71	0.296675373	0.332220525	0.296675373	0.332220525
β1	0.019667961	0.000396717	49.57683267	1.11119E-90	0.018883631	0.020452291	0.018883631	0.020452291
β2	-0.000140635	4.76668E-06	-29.50377541	5.91881E-62	-0.000150059	-0.000131211	-0.000150059	-0.000131211
β3	3.41221E-07	1.553E-08	21.97170644	3.23018E-47	3.10517E-07	3.71924E-07	3.10517E-07	3.71924E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994725637
R Square	0.989479094
Adjusted R Square	0.989253646
Standard Error	0.026400955
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.177423888	3.059141296	4388.946164	3.302E-138
Residual	140	0.097581462	0.00069701		
Total	143	9.275005349			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.307250046	0.008872414	34.62981435	1.58839E-70	0.289708807	0.324791284	0.289708807	0.324791284
β1	0.019843369	0.000391553	50.6786443	6.01683E-92	0.019069248	0.020617491	0.019069248	0.020617491
β2	-0.000141338	4.70464E-06	-30.04217841	6.6318E-63	-0.000150639	-0.000132036	-0.000150639	-0.000132036
β3	3.42235E-07	1.53279E-08	22.32765206	5.59173E-48	3.11931E-07	3.72539E-07	3.11931E-07	3.72539E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994625665
R Square	0.989280214
Adjusted R Square	0.989050504
Standard Error	0.026521235
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.087590035	3.029196678	4306.653909	1.2247E-137
Residual	140	0.09847263	0.000703376		
Total	143	9.186062664			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.309274775	0.008912836	34.69993005	1.23231E-70	0.291653621	0.32689593	0.291653621	0.32689593
β1	0.019797213	0.000393337	50.33145871	1.49879E-91	0.019019565	0.020574861	0.019019565	0.020574861
β2	-0.000141221	4.72607E-06	-29.88132995	1.27149E-62	-0.000150565	-0.000131878	-0.000150565	-0.000131878
β3	3.42202E-07	1.53977E-08	22.22423366	9.29272E-48	3.1176E-07	3.72644E-07	3.1176E-07	3.72644E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994686146
R Square	0.98940053
Adjusted R Square	0.989173398
Standard Error	0.026467032
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.154328871	3.051442957	4356.069182	5.5581E-138
Residual	140	0.09807053	0.000700504		
Total	143	9.252399401			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.307664081	0.00889462	34.58990756	1.8356E-70	0.29007894	0.325249222	0.29007894	0.325249222
β1	0.019836272	0.000392533	50.53404116	8.79346E-92	0.019060214	0.020612331	0.019060214	0.020612331
β2	-0.000141357	4.71641E-06	-29.97123684	8.83426E-63	-0.000150681	-0.000132032	-0.000150681	-0.000132032
β3	3.42352E-07	1.53662E-08	22.27954719	7.08083E-48	3.11973E-07	3.72732E-07	3.11973E-07	3.72732E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.993880162
R Square	0.987797777
Adjusted R Square	0.987536301
Standard Error	0.027114753
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	8.332367897	2.777455966	3777.77319	1.0603E-133
Residual	140	0.102929375	0.00073521		
Total	143	8.435297272			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.326854136	0.009112296	35.86957101	1.8943E-72	0.308838638	0.344869634	0.308838638	0.344869634
β1	0.019394839	0.000402139	48.22916512	4.26E-89	0.018599788	0.02018989	0.018599788	0.02018989
β2	-0.000140183	4.83184E-06	-29.01231258	4.47722E-61	-0.000149736	-0.00013063	-0.000149736	-0.00013063
β3	3.41846E-07	1.57423E-08	21.71513554	1.15483E-46	3.10722E-07	3.72969E-07	3.10722E-07	3.72969E-07

Secondary Workover Costs

Secondary workover costs were calculated using an average from 2004 – 2007 data from the most recent Cost and Indices data base provided by the U.S. Energy Information Administration (EIA). Secondary workover costs consist of workover rig services, remedial services and equipment repair. The data was analyzed on a regional level. The secondary operations costs for each region were determined by multiplying the costs in West Texas by the ratio of primary operating costs. This method was used in the National Petroleum Council's (NPC) EOR study of 1984. The independent variable is depth. The form of the equation is given below:

$$Cost = \beta0 + \beta1 * Depth + \beta2 * Depth^2 + \beta3 * Depth^3 \qquad (2.B\text{-}15)$$

where Cost = SWK_W

β0 = OMSWRK

β1 = OMSWRA

β2 = OMSWRB

β3 = OMSWRC

from equation 2-33 in Chapter 2.

The cost is on a per well basis. Parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares. β2 and β3 are statistically insignificant and are therefore zero.

West Texas, applied to OLOGSS region 4:

Regression Statistics	
Multiple R	0.9993
R Square	0.9986
Adjusted R Square	0.9972
Standard Error	439.4
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	136,348,936	136,348,936	706	0
Residual	1	193,106	193,106		
Total	2	136,542,042			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	4,951.059	538.200	9.199	0.069	-1,887.392	11,789.510	-1,887.392	11,789.510
β1	2.703	0.102	26.572	0.024	1.410	3.995	1.410	3.995

South Texas, applied to OLOGSS region 2:

Regression Statistics	
Multiple R	0.9924
R Square	0.9849
Adjusted R Square	0.9811
Standard Error	1356.3
Observations	6

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	480,269,759	480,269,759	261	0
Residual	4	7,358,144	1,839,536		
Total	5	487,627,903			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	10,560.069	1,174.586	8.990	0.001	7,298.889	13,821.249	7,298.889	13,821.249
β1	3.587	0.222	16.158	0.000	2.970	4.203	2.970	4.203

Mid-Continent, applied to OLOGSS region 3:

Regression Statistics	
Multiple R	0.9989
R Square	0.9979
Adjusted R Square	0.9958
Standard Error	544.6
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	140,143,261	140,143,261	473	0
Residual	1	296,583	296,583		
Total	2	140,439,844			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,732.510	666.989	5.596	0.113	-4,742.355	12,207.375	-4,742.355	12,207.375
β1	2.740	0.126	21.738	0.029	1.138	4.342	1.138	4.342

Rocky Mountains, applied to OLOGSS region 1, 5, and 7:

Regression Statistics	
Multiple R	0.9996
R Square	0.9991
Adjusted R Square	0.9983
Standard Error	290.9
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	98,740,186	98,740,186	1,167	0
Residual	1	84,627	84,627		
Total	2	98,824,812			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	5,291.954	356.287	14.853	0.043	764.922	9,818.987	764.922	9,818.987
β1	2.300	0.067	34.158	0.019	1.444	3.155	1.444	3.155

West Coast, applied to OLOGSS region 6:

Regression Statistics	
Multiple R	0.9991
R Square	0.9983
Adjusted R Square	0.9966
Standard Error	454.7
Observations	3

ANOVA

	df	SS	MS	F	Significance F
Regression	1	120,919,119	120,919,119	585	0
Residual	1	206,762	206,762		
Total	2	121,125,881			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	4,131.486	556.905	7.419	0.085	-2,944.638	11,207.610	-2,944.638	11,207.610
β1	2.545	0.105	24.183	0.026	1.208	3.882	1.208	3.882

Secondary Workover Costs - Cost Adjustment Factor

The cost adjustment factor for secondary workover costs was calculated using data through 2008 from the Cost and Indices data base provided by EIA. The initial cost was normalized at various prices from $10 to $200 per barrel. This led to the development of a series of intermediate equations and the calculation of costs at specific prices and fixed depths. The differentials between estimated costs across the price range and fixed costs at $50 per barrel were then calculated. The cost factor equation was then estimated using the differentials. The method of estimation used was ordinary least squares. The form of the equation is given below:

$$\text{Cost} = \beta0 + \beta1 * \text{Oil Price} + \beta2 * \text{Oil Price}^2 + \beta3 * \text{Oil Price}^3$$

Rocky Mountains, Applied to OLOGSS Region 1, 5, and 7:

Regression Statistics	
Multiple R	0.994646805
R Square	0.989322267
Adjusted R Square	0.989093459
Standard Error	0.026416612
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.051925882	3.017308627	4323.799147	9.3015E-138
Residual	140	0.097697232	0.000697837		
Total	143	9.149623114			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312179978	0.008877675	35.1646082	2.31513E-71	0.294628337	0.329731619	0.294628337	0.329731619
β1	0.019705242	0.000391785	50.29605017	1.64552E-91	0.018930662	0.020479822	0.018930662	0.020479822
β2	-0.000140397	4.70743E-06	-29.82464336	1.6003E-62	-0.000149704	-0.000131091	-0.000149704	-0.000131091
β3	3.4013E-07	1.53369E-08	22.17714344	1.1716E-47	3.09808E-07	3.70452E-07	3.09808E-07	3.70452E-07

South Texas, Applied to OLOGSS Region 2:

Regression Statistics	
Multiple R	0.994648271
R Square	0.989325182
Adjusted R Square	0.989096436
Standard Error	0.026409288
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.049404415	3.016468138	4324.992582	9.1255E-138
Residual	140	0.097643067	0.00069745		
Total	143	9.147047482			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.31224985	0.008875214	35.18223288	2.17363E-71	0.294703075	0.329796624	0.294703075	0.329796624
β1	0.019703773	0.000391676	50.30624812	1.60183E-91	0.018929408	0.020478139	0.018929408	0.020478139
β2	-0.000140393	4.70612E-06	-29.83187838	1.55398E-62	-0.000149697	-0.000131088	-0.000149697	-0.000131088
β3	3.40125E-07	1.53327E-08	22.18299399	1.13834E-47	3.09811E-07	3.70439E-07	3.09811E-07	3.70439E-07

Mid-Continent, Applied to OLOGSS Region 3:

Regression Statistics	
Multiple R	0.994391906
R Square	0.988815263
Adjusted R Square	0.98857559
Standard Error	0.027366799
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.269694355	3.089898118	4125.685804	2.3918E-136
Residual	140	0.104851837	0.000748942		
Total	143	9.374546192			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.301399555	0.009196999	32.7715099	1.54408E-67	0.283216594	0.319582517	0.283216594	0.319582517
β1	0.020285999	0.000405877	49.980617	3.79125E-91	0.019483558	0.021088441	0.019483558	0.021088441
β2	-0.000145269	4.87675E-06	-29.78803686	1.85687E-62	-0.00015491	-0.000135627	-0.00015491	-0.000135627
β3	3.51144E-07	1.58886E-08	22.10035946	1.71054E-47	3.19731E-07	3.82556E-07	3.19731E-07	3.82556E-07

West Texas, Applied to OLOGSS Region 4:

Regression Statistics	
Multiple R	0.994645783
R Square	0.989320233
Adjusted R Square	0.989091381
Standard Error	0.026422924
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.054508298	3.018169433	4322.966602	9.4264E-138
Residual	140	0.097743924	0.000698171		
Total	143	9.152252223			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312146343	0.008879797	35.15242029	2.41837E-71	0.294590508	0.329702178	0.294590508	0.329702178
β1	0.019706241	0.000391879	50.28658391	1.68714E-91	0.018931476	0.020481006	0.018931476	0.020481006
β2	-0.000140397	4.70855E-06	-29.81743751	1.64782E-62	-0.000149706	-0.000131088	-0.000149706	-0.000131088
β3	3.4012E-07	1.53406E-08	22.17121727	1.20629E-47	3.09791E-07	3.70449E-07	3.09791E-07	3.70449E-07

West Coast, Applied to OLOGSS Region 6:

Regression Statistics	
Multiple R	0.994644139
R Square	0.989316964
Adjusted R Square	0.989088042
Standard Error	0.026428705
Observations	144

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	9.05566979	3.018556597	4321.629647	9.6305E-138
Residual	140	0.097786705	0.000698476		
Total	143	9.153456495			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	0.312123671	0.00888174	35.14217734	2.50872E-71	0.294563994	0.329683347	0.294563994	0.329683347
β1	0.019707015	0.000391964	50.27755672	1.72782E-91	0.01893208	0.020481949	0.01893208	0.020481949
β2	-0.0001404	4.70958E-06	-29.81159891	1.68736E-62	-0.000149711	-0.000131089	-0.000149711	-0.000131089
β3	3.40124E-07	1.5344E-08	22.16666321	1.23366E-47	3.09789E-07	3.7046E-07	3.09789E-07	3.7046E-07

Additional Cost Equations and Factors

The model uses several updated cost equations and factors originally developed for DOE/NETL's Comprehensive Oil and Gas Analysis Model (COGAM). These are:

- The crude oil and natural gas investment factors for tangible and intangible investments as well as the operating costs. These factors were originally developed based upon the 1984 Enhanced Oil Recovery Study completed by the National Petroleum Council.
- The G&A factors for capitalized and expensed costs.
- The limits on impurities, such as N2, CO2, and H2S used to calculate natural gas processing costs.
- Cost equations for stimulation, the produced water handling plant, the chemical handling plant, the polymer handling plant, CO_2 recycling plant, and the steam manifolds and pipelines.

Natural and Industrial CO2 Prices

The model uses regional CO_2 prices for both natural and industrial sources of CO_2. The cost equation for natural CO_2 is derived from the equation used in COGAM and updated to reflect current dollar values. According to University of Wyoming, this equation is applicable to the natural CO_2 in the Permian basin (Southwest). The cost of CO_2 in other regions and states is calculated using state calibration factors which represent the additional cost of transportation.

The industrial CO_2 costs contain two components: cost of capture and cost of transportation. The capture costs are derived using data obtained from Denbury Resources, Inc. and other sources. CO_2 capture costs range between $20 and $63/ton. The transportation costs were derived using an external economic model which calculates pipeline tariff based upon average distance, compression rate, and volume of CO_2 transported.

National Crude Oil Drilling Footage Equation

The equation for crude oil drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

$$\text{Oil Footage} = \beta 0 + \beta 1 * \text{Oil Price} \tag{2.B-16}$$

where $\beta 0 = \text{OILA0}$
$\beta 1 = \text{OILA1}$
from equation 2-99 in Chapter 2.

Oil footage is the footage of total developmental crude oil wells drilled in the United States in thousands of feet. The crude oil price is a rolling five year average of crude oil prices from 1995 – 2008. The parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Oil Footage
Current sample: (1999 to 2008)

Regression Statistics	
Multiple R	0.9623
R Square	0.9259
Adjusted R Square	0.9167
Standard Error	5,108.20
Observations	10

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2,609,812,096.02	2,609,812,096.02	100.02	0.00
Residual	8	208,749,712.88	26,093,714.11		
Total	9	2,818,561,808.90			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	3,984.11	4,377.97	0.91	0.39	-6,111.51	14,079.72	-6,111.51	14,079.72
β1	1,282.45	128.23	10.00	0.00	986.74	1,578.16	986.74	1,578.16

Regional Crude Oil Footage Distribution

The regional drilling distributions for crude oil were estimated using an updated EIA well count file. The percent allocations for each region are calculated using the average footage drilled from 2004 – 2008 for developed crude oil or natural gas fields.

Region Name	States Included	Oil
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	7.6%
Gulf Coast	AL,FL,LA,MS,TX	29.3%
Midcontinent	AR,KS,MO,NE,OK,TX	16.8%
Southwest	TX,NM	18.3%
Rocky Mountains	CO,NV,UT,WY,NM	10.7%
West Coast	CA,WA	9.6%
Northern Great Plains	MT,ND,SD	7.6%

National Natural Gas Drilling Footage Equation

The equation for natural gas drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

$$\text{Gas Footage} = \beta 0 + \beta 1 * \text{Gas Price} \qquad (2.B\text{-}17)$$

where $\beta 0 = GASA0$
$\beta 1 = GASA1$
from equation 2-100 in Chapter 2.

Gas footage is footage of total developmental natural gas wells drilled in the United States in thousands of feet. The gas price is a rolling five year average of natural gas prices from 1995 – 2008. The parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Gas Footage
Current sample: (1999 to 2008)

Regression Statistics	
Multiple R	0.9189
R Square	0.8444
Adjusted R Square	0.7666
Standard Error	9,554.63
Observations	4

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	990,785,019.79	990,785,019.79	10.85	0.08
Residual	2	182,581,726.21	91,290,863.10		
Total	3	1,173,366,746.00			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
β0	2,793.29	53,884.13	0.05	0.96	-229,051.57	234,638.14	-229,051.57	234,638.14
β1	30,429.72	9,236.81	3.29	0.08	-9,313.08	70,172.52	-9,313.08	70,172.52

Regional Natural Gas Footage Distribution

The regional drilling distributions for natural gas were estimated using an updated EIA well count file. The percent allocations for each region are calculated using the average footage drilled from 2004 – 2008 for developed crude oil or natural gas fields.

Region Name	States Included	Gas
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	13.2%
Gulf Coast	AL,FL,LA,MS,TX	18.7%
Midcontinent	AR,KS,MO,NE,OK,TX	13.4%
Southwest	TX,NM	34.5%
Rocky Mountains	CO,NV,UT,WY,NM	19.5%
West Coast	CA,WA	0.4%
Northern Great Plains	MT,ND,SD	0.4%

National Exploration Drilling Footage Equation

The equation for exploration well drilling footage was estimated for the time period 1999 - 2008. The drilling footage data was compiled from EIA's Annual Energy Review 2008. The form of the estimating equation is given by:

$$\text{Exploration Footage} = \beta 0 + \beta 1 * \text{Oil Price} \qquad (2.B\text{-}18)$$

where $\beta 0 = \text{EXPA0}$
$\beta 1 = \text{EXPA1}$

Exploration footage is footage of total exploratory crude oil, natural gas and dry wells drilled in the United States in thousands of feet. The crude oil price is a rolling five year average of oil prices from 1995 – 2008. The parameter estimates and regression diagnostics are given below. The method of estimation used was ordinary least squares.

Dependent variable: Exploration Footage
Current sample: (1999 to 2008)

Regression Statistics	
Multiple R	0.9467
R Square	0.8963
Adjusted R Square	0.8834
Standard Error	2,825.10
Observations	10

ANOVA

	df	SS	MS	F	Significance F
Regression	1	552,044,623.08	552,044,623.08	69.17	0.00
Residual	8	63,849,573.82	7,981,196.73		
Total	9	615,894,196.90			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
β0	4,733.91	2,421.24	1.96	0.09	-849.49	10,317.31	-849.49	10,317.31
β1	589.83	70.92	8.32	0.00	426.28	753.37	426.28	753.37

Regional Exploration Footage Distribution

The regional distribution for drilled exploration projects is also estimated using the updated EIA well count file. The percent allocations for each corresponding region are calculated using a 2004 – 2008 average of footage drilled for exploratory fields for both crude oil and natural gas.

Region Name	States Included	Exploration
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	22.3%
Gulf Coast	AL,FL,LA,MS,TX	9.0%
Midcontinent	AR,KS,MO,NE,OK,TX	28.8%
Southwest	TX,NM	14.3%
Rocky Mountains	CO,NV,UT,WY,NM	11.5%
West Coast	CA,WA	0.3%
Northern Great Plains	MT,ND,SD	13.8%

Regional Dryhole Rate for Discovered Projects

The percent allocation for existing regional dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each corresponding region. Existing dryhole rates calculate the projects which have already been discovered. The formula for the percentage is given below:

$$\text{Existing Dryhole Rate} = \text{Developed Dryhole} / \text{Total Drilling} \tag{2.B-19}$$

Region Name	States Included	Existing
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	5.8%
Gulf Coast	AL,FL,LA,MS,TX	9.4%
Midcontinent	AR,KS,MO,NE,OK,TX	13.2%
Southwest	TX,NM	9.7%
Rocky Mountains	CO,NV,UT,WY,NM	4.3%
West Coast	CA,WA	1.5%
Northern Great Plains	MT,ND,SD	5.2%

Regional Dryhole Rate for First Exploration Well Drilled

The percent allocation for undiscovered regional exploration dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each region. Undiscovered regional exploration dryhole rates calculate the rate for the first well drilled in an exploration project. The formula for the percentage is given below:

Undiscovered Exploration = Exploration Dryhole / (Exploration Gas + Exploration Oil)

Region Name	States Included	Undisc. Exp
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	30.8%
Gulf Coast	AL,FL,LA,MS,TX	167.8%
Midcontinent	AR,KS,MO,NE,OK,TX	76.4%
Southwest	TX,NM	86.2%
Rocky Mountains	CO,NV,UT,WY,NM	74.0%
West Coast	CA,WA	466.0%
Northern Great Plains	MT,ND,SD	46.9%

Regional Dryhole Rate for Subsequent Exploration Wells Drilled

The percent allocation for undiscovered regional developed dryhole rates was estimated using an updated EIA well count file. The percentage is determined by the average footage drilled from 2004 – 2008 for each corresponding region. Undiscovered regional developed dryhole rates calculate the rate for subsequent wells drilled in an exploration project. The formula for the percentage is given below:

Undiscovered Developed = (Developed Dryhole + Explored Dryhole) / Total Drilling (2.B-20)

Region Name	States Included	Undisc. Dev
Northeast	IN,IL,KY,MI,NY,OH,PA,TN,VA,WV	7.3%
Gulf Coast	AL,FL,LA,MS,TX	11.6%
Midcontinent	AR,KS,MO,NE,OK,TX	16.8%
Southwest	TX,NM	10.8%
Rocky Mountains	CO,NV,UT,WY,NM	6.5%
West Coast	CA,WA	1.8%
Northern Great Plains	MT,ND,SD	10.5%

National Rig Depth Rating

The national rig depth rating schedule was calculated using a three year average based on the Smith Rig Count as reported by *Oil and Gas Journal*. Percentages are applied to determine the cumulative available rigs for drilling.

Appendix 2.C: Play-level Resource Assumptions for Tight Gas, Shale Gas, and Coalbed Methane

The detailed resource assumptions underlying the estimates of remaining unproved technically recoverable resources for tight gas, shale gas, and coalbed methane are presented in the following tables.

Table 2.C-1. Remaining Technically Recoverable Resources (TRR) – Tight Gas

REGION	BASIN	PLAY	AREA (mi^2)	WELL SPACING	DEPTH (ft)	EUR (bcf/well)	OFFICIAL NO ACCESS	TRR (bcf)
1	Appalachian	Berea Sandstone	51863	8	4000	0.18	0%	11401
1	Appalachian	Clinton/Medina High	14773	8	5900	0.25	0%	6786
1	Appalachian	Clinton/Medina Moderate/Low	27281	15	5200	0.08	0%	16136
1	Appalachian	Tuscarora Sandstone	42495	8	8000	0.69	0%	1485
1	Appalachian	Upper Devonian High	12775	10	4600	0.21	0%	10493
1	Appalachian	Upper Devonian Moderate/Low	29808	10	5400	0.06	0%	5492
2	East Texas	Cotton Valley/Bossier	2730	12	12500	1.39	0%	36447
2	Texas-Gulf	Olmos	2500	4	5000	0.44	0%	3624
2	Texas-Gulf	Vicksburg	600	8	11000	2.36	0%	4875
2	Texas-Gulf	Wilcox/Lobo	1500	8	9500	1.60	0%	8532
3	Anadarko	Cherokee/Redfork	1500	4	8500	0.90	0%	1168
3	Anadarko	Cleveland	1500	4	6500	0.91	0%	3690
3	Anadarko	Granite Wash/Atoka	1500	4	13000	1.72	0%	6871
3	Arkoma	Arkoma Basin	1000	8	8000	1.30	0%	2281
4	Permian	Abo	1500	8	3800	1.00	0%	9158
4	Permian	Canyon	6000	8	4500	0.22	0%	11535
5	Denver	Denver/Jules	3500	16	4999	0.24	1%	12953
5	Greater Green River	Deep Mesaverde	16416	4	15100	0.41	8%	2939
5	Greater Green River	Fort Union/Fox Hills	3858	8	5000	0.70	12%	1062
5	Greater Green River	Frontier (Deep)	15619	4	17000	2.58	9%	11303
5	Greater Green River	Frontier (Moxa Arch)	2334	8	9500	1.20	15%	3414
5	Greater Green River	Lance	5500	8	10000	6.60	11%	31541
5	Greater Green River	Lewis	5172	8	9500	1.32	6%	18893
5	Greater Green River	Shallow Mesaverde (1)	5239	4	9750	1.25	8%	12606
5	Greater Green River	Shallow Mesaverde (2)	6814	8	10500	0.67	8%	17874
5	Piceance	Iles/Mesaverde	972	8	8000	0.73	5%	1858
5	Piceance	North Williams Fork/Mesaverde	1008	8	8000	0.65	2%	4278
5	Piceance	South Williams Fork/Mesaverde	1008	32	7000	0.65	9%	22402
5	San Juan	Central Basin/Dakota	3918	6	6500	0.49	7%	15007
5	San Juan	Central Basin/Mesaverde	3689	8	4500	0.72	2%	8737
5	San Juan	Picture Cliffs	6558	4	3500	0.48	2%	4899
5	Uinta	Basin Flank Mesaverde	1708	8	8000	0.99	33%	5767
5	Uinta	Deep Synclinal Mesaverde	2893	8	18000	0.99	2%	3292
5	Uinta	Tertiary East	1600	16	6000	0.58	16%	5910
5	Uinta	Tertiary West	1603	8	6500	4.06	57%	10630
5	Williston	High Potential	2000	4	2300	0.61	4%	2960
5	Williston	Low Potential	3000	4	2500	0.21	1%	1886
5	Williston	Moderate Potential	2000	4	2300	0.33	4%	2071
5	Wind River	Fort Union/Lance Deep	2500	4	14500	0.54	9%	4261
5	Wind River	Fort Union/Lance Shallow	1500	8	11000	1.17	0%	13197
5	Wind River	Mesaverde/Frontier Deep	250	4	17000	1.99	9%	1221
5	Wind River	Mesaverde/Frontier Shallow	250	4	13500	1.25	0%	1037
6	Columbia	Basin Centered	1500	8	13100	1.26	0%	7508

Table 2.C-2. Remaining Technically Recoverable Resources (TRR) – Shale Gas

REGION	BASIN	PLAY	AREA (mi^2)	WELL SPACING	DEPTH (ft)	EUR (bcf/well)	OFFICIAL NO ACCESS	TRR (bcf)
1	Appalachian	Cincinatti Arch	6000	4	1800	0.12	0%	1435
1	Appalachian	Devonian Big Sandy - Active	8675	8	3800	0.32	0%	6490
1	Appalachian	Devonian Big Sandy - Undeveloped	1994	8	3800	0.32	0%	940
1	Appalachian	Devonian Greater Siltstone Area	22914	11	2911	0.20	0%	8463
1	Appalachian	Devonian Low Thermal Maturity	45844	7	3000	0.30	0%	13534
1	Appalachian	Marcellus - Active	10622	8	6750	3.49	0%	177931
1	Appalachian	Marcellus - Undeveloped	84271	8	6750	1.15	0%	232443
1	Illinois	New Albany	1600	8	2750	1.09	0%	10947
1	Michigan	Antrim	12000	7	1400	0.28	0%	20512
2	Black Warrior	Floyd-Neal/Conasauga	2429	2	8000	0.92	0%	4465
2	TX-LA-MS Salt	Haynesville - Active	3574	8	12000	6.48	0%	60615
2	TX-LA-MS Salt	Haynesville - Undeveloped	5426	8	12000	1.50	0%	19408
2	West Gulf Coast	Eagle Ford - Dry	200	4	7000	5.50	0%	4378
2	West Gulf Coast	Eagle Ford - Wet	890	8	7000	2.31	0%	16429
3	Anadarko	Cana Woodford	688	4	13500	3.42	0%	5718
3	Anadarko	Woodford - Central Oklahoma	1800	4	5000	1.01	0%	2946
3	Arkoma	Fayetteville - Central	4000	8	4000	2.29	0%	29505
3	Arkoma	Fayetteville - West	5000	8	4000	1.17	0%	4639
3	Arkoma	Woodford - Western Arkoma	2900	4	9500	4.06	0%	19771
4	Fort Worth	Barnett - Fort Worth Active	2649	5	7500	1.60	0%	15834
4	Fort Worth	Barnett - Fort Worth Undeveloped	477	8	7500	1.20	0%	4094
4	Permian	Barnett - Permian Active	1426	5	7500	1.60	0%	19871
4	Permian	Barnett - Permian Undeveloped	1906	8	7500	1.20	0%	15823
4	Permian	Barnett-Woodford	2691	4	10200	2.99	0%	32152
5	Greater Green River	Hilliard-Baxter-Mancos	16416	8	14750	0.18	0%	3770
5	San Juan	Lewis	7506	3	4500	1.53	0%	11638
5	Uinta	Mancos	6589	8	15250	1.00	0%	21021
5	Williston	Shallow Niobrara	10000	2	1000	0.46	4%	6757

Table 2.C-3. Remaining Technically Recoverable Resources (TRR) – Coalbed Methane

REGION	BASIN	PLAY	AREA (mi^2)	WELL SPACING	DEPTH (ft)	EUR (bcf/well)	OFFICIAL NO ACCESS	TRR (bcf)
1	Appalachian	Central Basin	3870	8	1900	0.18	0%	1709
1	Appalachian	North Appalachia - High	3817	12	1400	0.12	0%	532
1	Appalachian	North Appalachia - Mod/Low	8906	12	1800	0.08	0%	469
1	Illinois	Central Basin	1214	8	1000	0.12	0%	1161
2	Black Warrior	Extention Area	700	8	1900	0.08	0%	931
2	Black Warrior	Main Area	1000	12	1950	0.21	0%	2190
2	Cahaba	Cahaba Coal Field	387	8	3000	0.18	0%	379
3	Midcontinent	Arkoma	2998	8	1500	0.22	0%	3032
3	Midcontinent	Cherokee & Forest City	2750	8	1000	0.06	0%	1308
4	Raton	Southern	386	8	2000	0.37	2%	962
5	Greater Green River	Deep	3600	4	7000	0.60	15%	3879
5	Greater Green River	Shallow	720	8	1500	0.20	20%	1053
5	Piceance	Deep	2000	4	7000	0.60	3%	3677
5	Piceance	Divide Creek	144	8	3800	0.18	13%	194
5	Piceance	Shallow	2000	4	3500	0.30	9%	2230
5	Piceance	White River Dome	216	8	7500	0.41	8%	657
5	Powder River	Big George/Lower Fort Union	2880	16	1100	0.26	1%	5943
5	Powder River	Wasatch	216	8	1100	0.06	1%	92
5	Powder River	Wyodak/Upper Fort Union	3600	20	600	0.14	1%	18859
5	Raton	Northern	470	8	2500	0.35	0%	957
5	Raton	Purgatoire River	360	8	2000	0.31	0%	430
5	San Juan	Fairway NM	670	4	3250	1.14	7%	774
5	San Juan	North Basin	2060	4	3000	0.28	7%	1511
5	San Juan	North Basin CO	780	4	2800	1.51	7%	10474
5	San Juan	South Basin	1190	4	2000	0.20	7%	820
5	San Juan	South Menefee NM	7454	5	2500	0.10	7%	177
5	Uinta	Blackhawk	586	8	3250	0.16	5%	1864
5	Uinta	Ferron	400	8	3000	0.78	11%	1409
5	Uinta	Sego	534	4	3250	0.31	10%	417

3. Offshore Oil and Gas Supply Submodule

Introduction

The Offshore Oil and Gas Supply Submodule (OOGSS) uses a field-based engineering approach to represent the exploration and development of U.S. offshore oil and natural gas resources. The OOGSS simulates the economic decision-making at each stage of development from frontier areas to post-mature areas. Offshore petroleum resources are divided into 3 categories:

- **Undiscovered Fields.** The number, location, and size of the undiscovered fields is based on the Minerals Management Service's (MMS) 2006 hydrocarbon resource assessment.[1] MMS was renamed Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) in 2010.

- **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 by 2009. The production volumes are from the BOEMRE production 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. The crosswalk between region and evaluation unit is shown in Table 3-1.

Supply curves for crude oil and natural gas are generated for three offshore regions: Pacific, Atlantic, and Gulf of Mexico. 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.

Undiscovered Fields Component

Significant undiscovered oil and gas resources are estimated to exist in the Outer Continental Shelf, particularly in the Gulf of Mexico. Exploration and development of these resources is projected in this component of the OOGSS.

Within each evaluation unit, a field size distribution is assumed based on BOEMRE's latest[1] resource assessment (Table 3-2). The volume of resource in barrels of oil equivalence by field size class as defined by the BOEMRE is shown in Table 3-3. In the OOGSS, the mean estimate represents the size of each field in the field size class. Water depth and field size class are used for specifying many of the technology assumptions in the OOGSS. Fields smaller than field size class 2 are assumed to be uneconomic to develop.

[1] U.S. Department of Interior, Minerals Management Service, *Report to Congress: Comprehensive Inventory of U.S.OCS Oil and Natural Gas Resources*, February 2006.

Table 3-1. Offshore Region and Evaluation Unit Crosswalk

No.	Region Name	Planning Area	Water Depth (meters)	Drilling Depth (feet)	Evaluation Unit Name	Region ID
1	Shallow GOM	Western GOM	0 - 200	< 15,000	WGOM0002	3
2	Shallow GOM	Western GOM	0 - 200	> 15,000	WGOMDG02	3
3	Deep GOM	Western GOM	201 - 400	All	WGOM0204	4
4	Deep GOM	Western GOM	401 - 800	All	WGOM0408	4
5	Deep GOM	Western GOM	801 - 1,600	All	WGOM0816	4
6	Deep GOM	Western GOM	1,601 - 2,400	All	WGOM1624	4
7	Deep GOM	Western GOM	> 2,400	All	WGOM2400	4
8	Shallow GOM	Central GOM	0 - 200	< 15,000	CGOM0002	3
9	Shallow GOM	Central GOM	0 - 200	> 15,000	CGOMDG02	3
10	Deep GOM	Central GOM	201 - 400	All	CGOM0204	4
11	Deep GOM	Central GOM	401 - 800	All	CGOM0408	4
12	Deep GOM	Central GOM	801 - 1,600	All	CGOM0816	4
13	Deep GOM	Central GOM	1,601 – 2,400	All	CGOM1624	4
14	Deep GOM	Central GOM	> 2,400	All	CGOM2400	4
15	Shallow GOM	Eastern GOM	0 - 200	All	EGOM0002	3
16	Deep GOM	Eastern GOM	201 - 400	All	EGOM0204	4
17	Deep GOM	Central GOM	401 - 800	All	EGOM0408	4
18	Deep GOM	Eastern GOM	801 - 1600	All	EGOM0816	4
19	Deep GOM	Eastern GOM	1601 - 2400	All	EGOM1624	4
20	Deep GOM	Eastern GOM	> 2400	All	EGOM2400	4
21	Deep GOM	Eastern GOM	> 200	All	EGOML181	4
22	Atlantic	North Atlantic	0 - 200	All	NATL0002	1
23	Atlantic	North Atlantic	201 - 800	All	NATL0208	1
24	Atlantic	North Atlantic	> 800	All	NATL0800	1
25	Atlantic	Mid Atlantic	0 - 200	All	MATL0002	1
26	Atlantic	Mid Atlantic	201 - 800	All	MATL0208	1
27	Atlantic	Mid Atlantic	> 800	All	MATL0800	1
28	Atlantic	South Atlantic	0 - 200	All	SATL0002	1
29	Atlantic	South Atlantic	201 - 800	All	SATL0208	1
30	Atlantic	South Atlantic	> 800	All	SATL0800	1
31	Atlantic	Florida Straits	0 – 200	All	FLST0002	1
32	Atlantic	Florida Straits	201 - 800	All	FLST0208	1
33	Atlantic	Florida Straits	> 800	All	FLST0800	1
34	Pacific	Pacific Northwest	0-200	All	PNW0002	2
35	Pacific	Pacific Northwest	201-800	All	PNW0208	2
36	Pacific	North California	0-200	All	NCA0002	2
37	Pacific	North California	201-800	All	NCA0208	2
38	Pacific	North California	801-1600	All	NCA0816	2
39	Pacific	North California	1600-2400	All	NCA1624	2
40	Pacific	Central California	0-200	All	CCA0002	2
41	Pacific	Central California	201-800	All	CCA0208	2
42	Pacific	Central California	801-1600	All	CCA0816	2
43	Pacific	South California	0-200	All	SCA0002	2
44	Pacific	South California	201-800	All	SCA0208	2
45	Pacific	South California	801-1600	All	SCA0816	2
46	Pacific	South California	1601-2400	All	SCA1624	2

Source: U.S. Energy Information Administration, Energy Analysis, Office of Petroleum, Gas, and Biofuels Analysis

Table 3-2. Number of Undiscovered Fields by Evaluation Unit and Field Size Class, as of January 1, 2003

Evaluation Unit	Field Size Class (FSC)																Number of Fields	Total Resource (BBOE)
	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17		
WGOM0002	1	5	11	14	20	23	24	27	30	8	6	8	2	0	0	0	179	4.348
WGOMDG02	0	0	2	4	5	6	8	9	9	3	2	2	1	0	0	0	51	1.435
WGOM0204	0	0	0	0	0	0	2	3	3	4	2	1	1	0	0	0	16	1.027
WGOM0408	0	0	0	0	0	1	3	3	7	7	3	2	1	0	0	0	27	1.533
WGOM0816	0	0	0	0	0	0	4	7	16	16	15	9	3	2	1	0	73	8.082
WGOM1624	0	0	0	1	2	6	10	14	18	18	14	10	6	4	1	0	104	10.945
WGOM2400	0	0	0	0	2	3	3	6	7	6	5	3	3	2	0	0	40	4.017
CGOM0002	1	1	6	11	28	52	79	103	81	53	20	1	0	0	0	0	436	8.063
CGOMDG02	0	0	1	1	4	4	4	6	7	6	5	3	1	0	0	0	42	3.406
CGOM0204	0	0	0	0	0	0	1	2	3	2	2	2	1	0	0	0	13	1.102
CGOM0408	0	0	0	0	0	1	1	4	4	4	1	1	1	1	0	0	18	1.660
CGOM0816	0	0	0	0	2	4	8	11	20	22	19	14	7	3	1	0	111	11.973
CGOM1624	0	0	0	1	2	5	9	15	18	19	15	13	8	4	1	0	110	12.371
CGOM2400	0	0	0	0	2	2	3	5	5	5	5	4	3	2	0	0	36	4.094
EGOM0002	4	6	7	11	16	18	18	16	13	10	6	1	0	0	0	0	126	1.843
EGOM0204	0	1	1	2	3	4	4	3	1	1	1	0	0	0	0	0	21	0.233
EGOM0408	0	1	2	3	5	5	5	4	3	2	1	0	0	0	0	0	31	0.348
EGOM0816	0	1	1	3	4	4	4	3	3	2	1	0	0	0	0	0	26	0.326
EGOM1624	0	0	0	0	2	1	1	1	0	1	0	1	0	0	0	0	7	0.250
EGOM2400	0	0	0	1	1	3	5	7	8	9	7	6	3	2	0	0	52	4.922
EGOML181	0	0	0	0	1	3	3	5	8	5	4	2	2	1	1	0	35	1.836
NATL0002	5	7	10	14	16	17	15	11	10	8	3	2	1	0	0	0	119	1.896
NATL0208	1	1	1	2	2	3	3	3	2	1	1	0	0	0	0	0	20	0.246
NATL0800	1	2	3	5	7	10	13	12	7	6	4	1	0	0	0	0	71	1.229
MATL0002	4	6	8	12	13	14	13	11	8	7	5	2	0	0	0	0	103	1.585
MATL0208	1	1	2	3	3	3	3	4	2	2	2	2	0	0	0	0	28	0.377
MATL0800	2	4	5	8	9	10	10	8	5	5	3	2	0	0	0	0	71	1.173
SATL0002	1	2	2	3	5	6	5	5	4	4	1	1	0	0	0	0	39	0.658
SATL0208	4	5	7	10	12	13	12	10	8	7	3	2	0	0	0	0	93	1.382
SATL0800	2	2	4	5	9	15	20	17	11	7	2	1	1	0	0	0	96	1.854
FLST0002	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1	0.012
FLST0208	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	2	0.009
FLST0800	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.000
PNW0002	10	17	24	29	27	21	13	8	5	2	1	0	0	0	0	0	157	0.597
PNW0208	4	6	9	10	11	7	6	3	2	1	0	0	0	0	0	0	59	0.209
NCA0002	1	2	3	5	5	5	5	4	3	3	2	0	0	0	0	0	38	0.485
NCA0208	9	17	24	28	26	22	15	10	5	3	1	1	0	0	0	0	161	0.859
NCA0816	3	6	9	12	12	11	9	7	4	3	2	1	0	0	0	0	79	0.784
NCA1624	1	2	3	5	6	6	7	6	4	2	1	1	0	0	0	0	44	0.595
CCA0002	1	4	6	11	15	19	20	17	12	8	4	2	0	0	0	0	119	1.758
CCA0208	1	2	3	5	8	10	10	8	7	5	2	0	0	0	0	0	61	0.761
CCA0816	0	1	1	2	3	4	5	3	2	2	0	0	0	0	0	0	23	0.218
SCA0002	1	2	4	10	16	21	22	19	12	6	2	1	0	0	0	0	116	1.348
SCA0208	3	6	12	25	38	49	51	43	28	14	5	3	1	0	0	0	278	3.655
SCA0816	1	3	6	9	13	17	18	15	12	8	2	2	1	0	0	0	107	1.906
SCA1624	0	1	2	3	4	5	5	5	4	3	1	1	0	0	0	0	34	0.608

Source: U.S. Energy Information Administration, Energy Analysis, Office of Petroleum, Gas, and Biofuels Analysis

Table 3-3. BOEMRE Field Size Definition (MMBOE)

Field Size Class	Mean
2	0.083
3	0.188
4	0.356
5	0.743
6	1.412
7	2.892
8	5.919
9	11.624
10	22.922
11	44.768
12	89.314
13	182.144
14	371.727
15	690.571
16	1418.883
17	2954.129

Source: Bureau of Ocean Energy Management, Regulation, and Enforcement

Projection of Discoveries

The number and size of discoveries is projected based on a simple model developed by J. J. Arps and T. G. Roberts in 1958[2]. For a given evaluation unit in the OOGSS, the number of cumulative discoveries for each field size class is determined by

$$\text{DiscoveredFields}_{\text{EU,iFSC}} = \text{TotalFields}_{\text{EU,iFSC}} * (1 - e^{\gamma_{\text{EU,iFSC}} * \text{CumNFW}_{\text{EU}}}) \quad (3\text{-}1)$$

where,

TotalFields	=	Total number of fields by evaluation unit and field size class
CumNFW	=	Cumulative new field wildcats drilled in an evaluation unit
γ	=	search coefficient
EU	=	evaluation unit
iFSC	=	field size class.

The search coefficient (γ) was chosen to make the Equation 3-1 fit the data. In many cases, however, the sparse exploratory activity in an evaluation unit made fitting the discovery model problematic. To provide reasonable estimates of the search coefficient in every evaluation unit, the data in various field size classes within a region were grouped as needed to obtain enough data points to provide a reasonable fit to the discovery model. A polynomial was fit to all of the relative search coefficients in the region. The polynomial was fit to the resulting search coefficients as follows:

[2]Arps, J. J. and T. G. Roberts, *Economics of Drilling for Cretaceous Oil on the East Flank of the Denver-Julesburg Basin*, Bulletin of the American Association of Petroleum Geologists, November 1958.

$$\gamma_{\mathrm{EU,iFSC}} = \beta 1 * \mathrm{iFSC}^2 + \beta 2 * \mathrm{iFSC} + \beta 3 * \gamma_{\mathrm{EU,10}} \tag{3-2}$$

where

β1	=	0.0243 for Western GOM and 0.0399 for Central and Eastern GOM
β2	=	-0.3525 for Western GOM and -0.6222 for Central and Eastern GOM
β3	=	1.5326 for Western GOM and 2.2477 for Central and 3.0477 for Eastern GOM
iFSC	=	field size class
γ	=	search coefficient for field size class 10.

Cumulative new field wildcat drilling is determined by

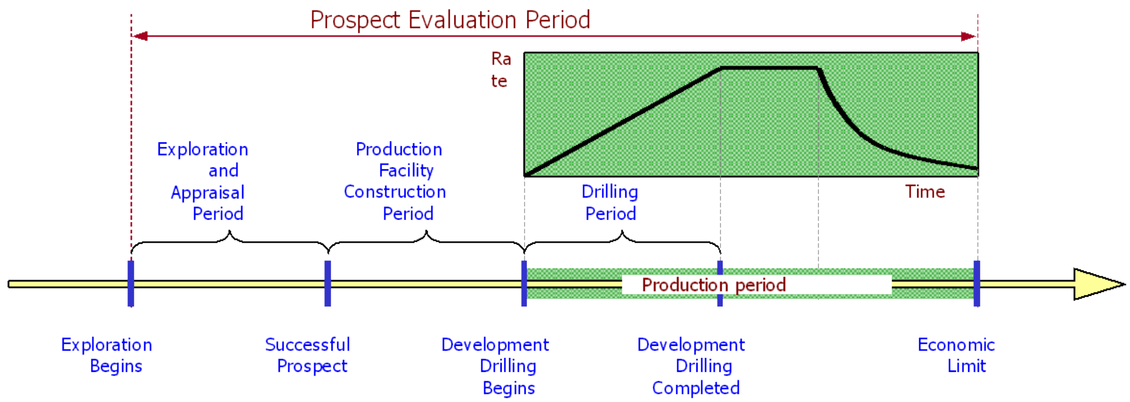
$$\mathrm{CumNFW}_{\mathrm{EU,t}} = \mathrm{CumNFW}_{\mathrm{EU,t-1}} + \alpha 1_{\mathrm{EU}} + \beta_{\mathrm{EU}} * (\mathrm{OILPRICE}_{\mathrm{t-nlag1}} * \mathrm{GASPRICE}_{\mathrm{t-nlag2}}) \tag{3-3}$$

where

OILPRICE	=	oil wellhead price
GASPRICE	=	natural gas wellhead price
α1, β	=	estimated parameter
nlag1	=	number of years lagged for oil price
nlag2	=	number of years lagged for gas price
EU	=	evaluation unit

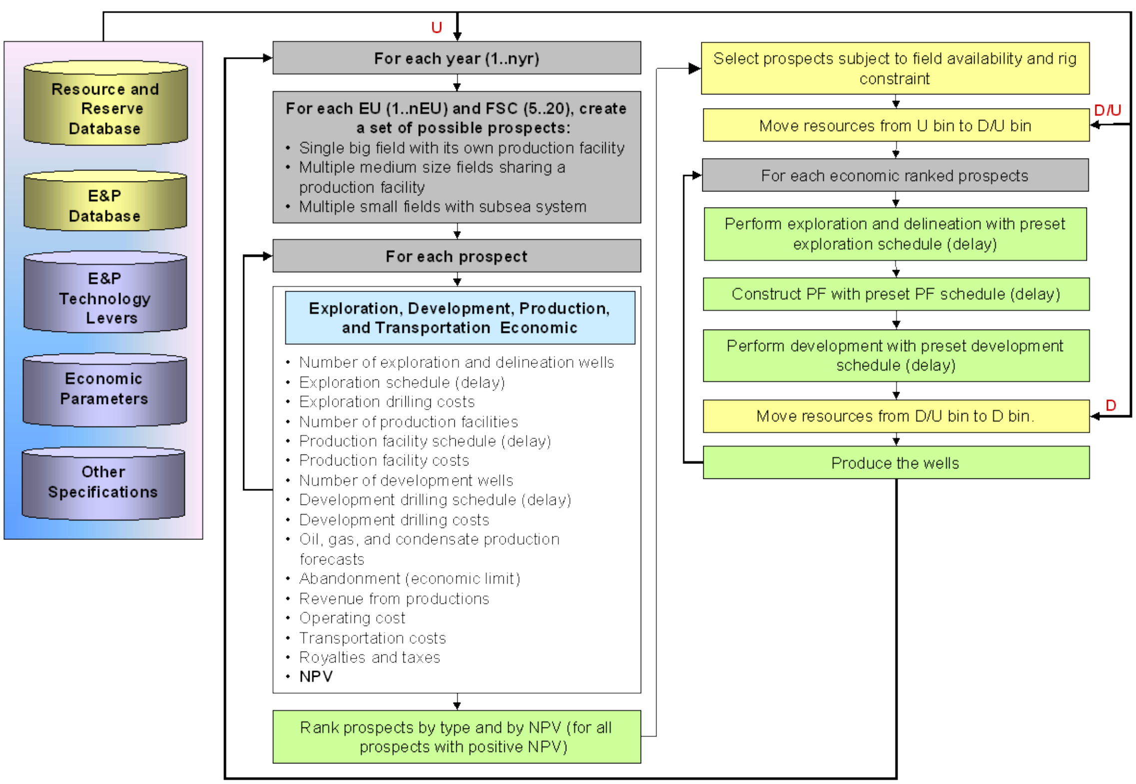
The decision for exploration and development of the discoveries determine from Equation 3-1 is performed at a prospect level that could involve more than one field. A prospect is defined as a potential project that covers exploration, appraisal, production facility construction, development, production, and transportation (Figure 3-1). There are three types of prospects: (1) a single field with its own production facility, (2) multiple medium size fields sharing a production facility, and (3) multiple small fields utilizing nearby production facility. The net present value (NPV) of each possible prospect is generated using the calculated exploration costs, production facility costs, development costs, completion costs, operating costs, flowline costs, transportation costs, royalties, taxes, and production revenues. Delays for exploration, production facility construction, and development are incorporated in this NPV calculation. The possible prospects are then ranked from best (highest NPV) to worst (lowest NPV). The best prospects are selected subject to field availability and rig constraint. The basic flowchart is presented in Figure 3-2.

Figure 3-1. Prospect Exploration, Development, and Production Schedule



Source: ICF Consulting

Figure 3-2. Flowchart for the Undiscovered Field Component of the OOGSS



Note: U = Undiscovered, D/U = Discovered/Undeveloped, D=Developed
Source: ICF Consulting

Calculation of Costs

The technology employed in the deepwater offshore areas to find and develop hydrocarbons can be significantly different than that used in shallower waters, and represents significant challenges for the companies and individuals involved in the deepwater development projects. In many situations in the deepwater OCS, the choice of technology used in a particular situation depends on the size of the prospect being developed. The following base costs are adjusted with the oil price to capture the variation in costs over time as activity level and demand for equipment and other supplies change. The adjustment factor is [1 + (oilprice/baseprice – 1)*0.4], where baseprice = $30/barrel.

Exploration Drilling

During the exploration phase of an offshore project, the type of drilling rig used depends on both economic and technical criteria. Offshore exploratory drilling usually is done using self-contained rigs that can be moved easily. Three types of drilling rigs are incorporated into the OOGSS. The exploration drilling costs per well for each rig type are a function of water depth (WD) and well drilling depth (DD), both in feet.

Jack-up rigs are limited to a water depth of about 600 feet or less. Jack-ups are towed to their location where heavy machinery is used to jack the legs down into the water until they rest on the ocean floor. When this is completed, the platform containing the work area rises above the water. After the platform has risen about 50 feet out of the water, the rig is ready to begin drilling.

$$\text{ExplorationDrillingCosts(\$/well)} = 2{,}000{,}000 + (5.0\text{E-}09)*WD*DD^3 \tag{3-4}$$

Semi-submersible rigs are floating structures that employ large engines to position the rig over the hole dynamically. This extends the maximum operating depth greatly, and some of these rigs can be used in water depths up to and beyond 3,000 feet. The shape of a semisubmersible rig tends to dampen wave motion greatly regardless of wave direction. This allows its use in areas where wave action is severe.

$$\text{ExplorationDrillingCosts(\$/well)} = 2{,}500{,}000 + 200*(WD+DD) + WD*(400+(2.0\text{E-}05)*DD^2) \tag{3-5}$$

Dynamically positioned drill ships are a second type of floating vessel used in offshore drilling. They are usually used in water depths exceeding 3,000 feet where the semi-submersible type of drilling rigs can not be deployed. Some of the drillships are designed with the rig equipment and anchoring system mounted on a central turret. The ship is rotated about the central turret using thrusters so that the ship always faces incoming waves. This helps to dampen wave motion.

$$\text{ExplorationDrillingCosts(\$/well)} = 7{,}000{,}000 + (1.0\text{E-}05)*WD*DD^2 \tag{3-6}$$

Water depth is the primary criterion for selecting a drilling rig. Drilling in shallow waters (up to 1,500 feet) can be done with jack-up rigs. Drilling in deeper water (greater than 1,500 feet) can be done with semi-submersible drilling rigs or drill ships. The number of rigs available for exploration is limited and varies by water depth levels. Drilling rigs are allowed to move one water depth level lower if needed.

Production and Development Structure

Six different options for development/production of offshore prospects are currently assumed in OOGSS, based on those currently considered and/or employed by operators in Gulf of Mexico OCS. These are the conventional fixed platforms, the compliant towers, tension leg platforms, Spar platforms, floating production systems and subsea satellite well systems. Choice of platform tends to be a function of the size of field and water depth, though in reality other operational, environmental, and/or economic decisions influence the choice. Production facility costs are a function of water depth (WD) and number of slots per structure (SLT).

Conventional Fixed Platform (FP). A fixed platform consists of a jacket with a deck placed on top, providing space for crew quarters, drilling rigs, and production facilities. The jacket is a tall vertical section made of tubular steel members supported by piles driven into the seabed. The fixed platform is economical for installation in water depths up to 1,200 feet. Although advances in engineering design and materials have been made, these structures are not economically feasible in deeper waters.

$$\text{StructureCost}(\$) = 2{,}000{,}000 + 9{,}000 * \text{SLT} + 1{,}500 * \text{WD} * \text{SLT} + 40 * \text{WD}^2 \qquad (3\text{-}7)$$

Compliant Towers (CT). The compliant tower is a narrow, flexible tower type of platform that is supported by a piled foundation. Its stability is maintained by a series of guy wires radiating from the ower and terminating on pile or gravity anchors on the sea floor. The compliant tower can withstand significant forces while sustaining lateral deflections, and is suitable for use in water depths of 1,200 to 3,000 feet. A single tower can accommodate up to 60 wells; however, the compliant tower is constrained by limited deck loading capacity and no oil storage capacity.

$$\text{StructureCost}(\$) = (\text{SLT} + 30) * (1{,}500{,}000 + 2{,}000 * (\text{WD} - 1{,}000)) \qquad (3\text{-}8)$$

Tension Leg Platform (TLP). The tension leg platform is a type of semi-submersible structure which is attached to the sea bed by tubular steel mooring lines. The natural buoyancy of the platform creates an upward force which keeps the mooring lines under tension and helps maintain vertical stability. This type of platform becomes a viable alternative at water depths of 1,500 feet and is considered to be the dominant system at water depths greater than 2,000 feet. Further, the costs of the TLP are relatively insensitive to water depth. The primary advantages of the TLP are its applicability in ultra-deepwaters, an adequate deck loading capacity, and some oil storage capacity. In addition, the field production time lag for this system is only about 3 years.

$$\text{StructureCost}(\$) = (\text{SLT} + 30) * (3{,}000{,}000 + 750 * (\text{WD} - 1{,}000)) \qquad (3\text{-}9)$$

Floating Production System (FPS). The floating production system, a buoyant structure, consists of a semi-submersible or converted tanker with drilling and production equipment anchored in place with wire rope and chain to allow for vertical motion. Because of the movement of this structure in severe environments, the weather-related production downtime is estimated to be about 10 percent. These structures can only accommodate a maximum of approximately 25 wells. The wells are completed subsea on the ocean floor and are connected to the production deck through a riser system designed to accommodate platform motion. This system is suitable for marginally economic fields in water depths up to 4,000 feet.

$$\text{StructureCost}(\$) = (\text{SLT} + 20) * (7{,}500{,}000 + 250 * (\text{WD} - 1{,}000)) \tag{3-10}$$

Spar Platform (SPAR). A Spar Platform consists of a large diameter single vertical cylinder supporting a deck. It has a typical fixed platform topside (surface deck with drilling and production equipment), three types of risers (production, drilling, and export), and a hull which is moored using a taut caternary system of 6 to 20 lines anchored into the seafloor. Spar platforms are presently used in water depths up to 3,000 feet, although existing technology is believed to be able to extend this to about 10,000 feet.

$$\text{StructureCost}(\$) = (\text{SLT} + 20) * (3{,}000{,}000 + 500 * (\text{WD} - 1{,}000)) \tag{3-11}$$

Subsea Wells System (SS). Subsea systems range from a single subsea well tied back to a nearby production platform (such as FPS or TLP) to a set of multiple wells producing through a common subsea manifold and pipeline system to a distant production facility. These systems can be used in water depths up to at least 7,000 feet. Since the cost to complete a well is included in the development well drilling and completion costs, no cost is assumed for the subsea well system. However, a subsea template is required for all development wells producing to any structure other than a fixed platform.

$$\text{SubseaTemplateCost}(\$ / \text{well}) = 2{,}500{,}000 \tag{3-12}$$

The type of production facility for development and production depends on water depth level as shown in Table 3-4.

Table 3-4. Production Facility by Water Depth Level

Water Depth Range (feet)		Production Facility Type					
Minimum	Maximum	FP	CT	TLP	FPS	SPAR	SS
0	656	X					X
656	2625		X				X
2625	5249			X			X
5249	7874				X	X	X
7874	10000				X	X	X

Source: ICF Consulting

Development Drilling

Pre-drilling of development wells during the platform construction phase is done using the drilling rig employed for exploration drilling. Development wells drilled after installation of the platform which also serves as the development structure is done using the platform itself. Hence, the choice of drilling rig for development drilling is tied to the choice of the production platform.

For water depths less than or equal to 900 meters,

$$\begin{aligned}\text{DevelopmentDrillingCost}(\$/\text{well}) &= 1{,}500{,}000 + (1{,}500 + 0.04 * \text{DD}) * \text{WD} \\ &+ (0.035 * \text{DD} - 300) * \text{DD}\end{aligned} \tag{3-13}$$

For water depths greater tan 900 meters,

$$\begin{aligned}\text{DevelopmentDrillingCost}(\$/\text{well}) &= 4{,}500{,}000 + (150 + 0.004 * \text{DD}) * \text{WD} \\ &+ (0.035 * \text{DD} - 250) * \text{DD}\end{aligned} \tag{3-14}$$

where

WD = water depth in feet
DD = drilling depth in feet.

Completion and Operating

Completion costs per well are a function of water depth range and drilling depth as shown in Table 3-5.

Table 3-5. Well Completion and Equipment Costs per Well

Water Depth (feet)	Development Drilling Depth (feet)		
	< 10,000	10,001 - 20,000	> 20,000
0 - 3,000	800,000	2,100,000	3,300,000
> 3,000	1,900,000	2,700,000	3,300,000

Platform operating costs for all types of structures are assumed to be a function of water depth (WD) and the number of slots (SLT). These costs include the following items:

- primary oil and gas production costs,
- labor,
- communications and safety equipment,
- supplies and catering services,
- routine process and structural maintenance,
- well service and workovers,
- insurance on facilities, and
- transportation of personnel and supplies.

Annual operating costs are estimated by

$$\text{OperatingCost}(\$ / \text{structure} / \text{year}) = 1{,}265{,}000 + 135{,}000 * \text{SLT} + 0.0588 * \text{SLT} * \text{WD}^2 \tag{3-15}$$

Transportation

It is assumed in the model that existing trunk pipelines will be used and that the prospect economics must support only the gathering system design and installation. However, in case of small fields tied back to some existing neighboring production platform, a pipeline is assumed to be required to transport the crude oil and natural gas to the neighboring platform.

Structure and Facility Abandonment

The costs to abandon the development structure and production facilities depend on the type of production technology used. The model projects abandonment costs for fixed platforms and compliant towers assuming that the structure is abandoned. It projects costs for tension leg platforms, converted semi-submersibles, and converted tankers assuming that the structures are removed for transport to another location for reinstallation. These costs are treated as intangible capital investments and are expensed in the year following cessation of production. Based on historical data, these costs are estimated as a fraction of the initial structure costs, as follows:

	Fraction of Initial Platform Cost
Fixed Platform	0.45
Compliant Tower	0.45
Tension Leg Platform	0.45
Floating Production Systems	0.15
Spar Platform	0.15

Exploration, Development, and Production Scheduling

The typical offshore project development consists of the following phases:[3]

- Exploration phase,
    - Exploration drilling program
    - Delineation drilling program
- Development phase,
- Fabrication and installation of the development/production platform,
    - Development drilling program
    - Pre-drilling during construction of platform
    - Drilling from platform
    - Construction of gathering system
- Production operations, and
- Field abandonment.

[3] The pre-development activities, including early field evaluation using conventional geological and geophysical methods and the acquisition of the right to explore the field, are assumed to be completed before initiation of the development of the prospect.

The timing of each activity, relative to the overall project life and to other activities, affects the potential economic viability of the undiscovered prospect. The modeling objective is to develop an exploration, development, and production plan which both realistically portrays existing and/or anticipated offshore practices and also allows for the most economical development of the field. A description of each of the phases is provided below.

Exploration Phase

An undiscovered field is assumed to be discovered by a successful exploration well (i.e., a new field wildcat). Delineation wells are then drilled to define the vertical and areal extent of the reservoir.

Exploration drilling. The exploration success rate (ratio of the number of field discovery wells to total wildcat wells) is used to establish the number of exploration wells required to discover a field as follows:

number of exploratory wells = 1/ [exploration success rate]

For example, a 25 percent exploration success rate will require four exploratory wells: one of the four wildcat wells drilled finds the field and the other three are dry holes.

Delineation drilling. Exploratory drilling is followed by delineation drilling for field appraisal (1 to 4 wells depending on the size of the field). The delineation wells define the field location vertically and horizontally so that the development structures and wells may be set in optimal positions. All delineation wells are converted to production wells at the end of the production facility construction.

Development Phase

During this phase of an offshore project, the development structures are designed, fabricated, and installed; the development wells (successful and dry) are drilled and completed; and the product transportation/gathering system is installed.

Development structures. The model assumes that the design and construction of any development structure begins in the year following completion of the exploration and delineation drilling program. However, the length of time required to complete the construction and installation of these structures depends on the type of system used. The required time for construction and installation of the various development structures used in the model is shown in Table 3-6. This time lag is important in all offshore developments, but it is especially critical for fields in deepwater and for marginally economic fields.

Development drilling schedule. The number of development wells varies by water depth and field size class as follows.

$$DevelopmentWells = \frac{5}{FSC} * FSIZE^{\beta_{DepthClass}} \tag{3-16}$$

where

FSC = field size class
FSIZE = resource volume (MMBOE)

β = 0.8 for water depths < 200 meters; 0.7 for water depths 200-800 meters; 0.65 for water depths > 800 meters.

Table 3-6. Production Facility Design, Fabrication, and Installation Period (Years)

PLATFORMS	**Water Depth (Feet)**														
Number of Slots	**0**	**100**	**400**	**800**	**1000**	**1500**	**2000**	**3000**	**4000**	**5000**	**6000**	**7000**	**8000**	**9000**	**10000**
2	1	1	1	1	1	1	1	1	2	2	3	3	4	4	4
8	2	2	2	2	2	2	2	2	2	2	3	3	4	4	4
12	2	2	2	2	2	2	2	2	2	2	3	3	4	4	4
18	2	2	2	2	2	2	2	2	2	3	3	3	4	4	4
24	2	2	2	2	2	2	2	2	2	3	3	4	4	4	5
36	2	2	2	2	2	2	2	2	2	3	3	4	4	4	5
48	2	2	2	2	2	2	3	3	3	3	4	4	4	4	5
60	2	2	2	2	2	2	3	3	3	3	4	4	4	4	5
OTHERS															
SS	1	1	1	1	1	1	2	2	2	3	3	3	4	4	4
FPS	[redacted]							3	3	3	4	4	4	4	5

Source: ICF Consulting

The development drilling schedule is determined based on the assumed drilling capacity (maximum number of wells that could be drilled in a year). This drilling capacity varies by type of production facility and water depth. For a platform type production facility (FP, CT, or TLP), the development drilling capacity is also a function of the number of slots. The assumed drilling capacity by production facility type is shown in Table 3-7.

Production transportation/gathering system. It is assumed in the model that the installation of the gathering systems occurs during the first year of construction of the development structure and is completed within 1 year.

Production Operations

Production operations begin in the year after the construction of the structure is complete. The life of the production depends on the field size, water depth, and development strategy. First production is from delineation wells that were converted to production wells. Development drilling starts at the end of the production facility construction period.

Table 3-7. Development Drilling Capacity by Production Facility Type

Maximum Number of Wells Drilled (wells/platform/year, 1 rig)	
Drilling Depth (feet)	**Drilling Capacity (24 slots)**
0	24
6000	24
7000	24
8000	20
9000	20
10000	20
11000	20
12000	16
13000	16
14000	12
15000	8
16000	4
17000	2
18000	2
19000	2
20000	2
30000	2

Maximum Number of Wells Drilled (wells/field/year)			
Water Depth (feet)	**SS**	**FPS**	**FPSO**
0	4		4
1000	4		4
2000	4		4
3000	4	4	4
4000	4	4	4
5000	3	3	3
6000	2	2	2
7000	2	2	2
8000	1	1	1
9000	1	1	1
10000	1	1	1

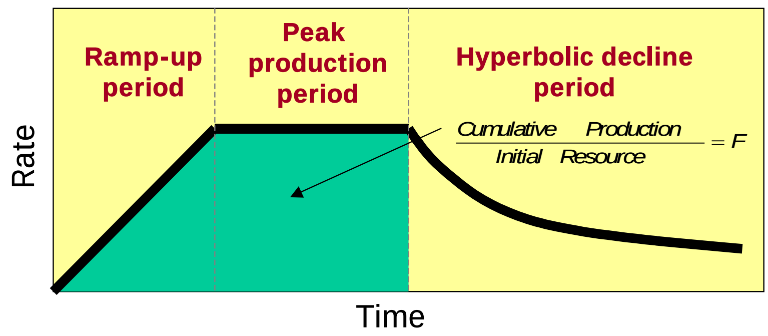
Source: ICF Consulting

Production profiles

The original hydrocarbon resource (in BOE) is divided between oil and natural gas using a user specified proportion. Due to the development drilling schedule, not all wells in the same field will produce at the same time. This yields a ramp-up profile in the early production period (Figure 3-3). The initial production rate is the same for all wells in the field and is constant for a period of time. Field production reaches its peak when all the wells have been drilled and start producing. The production will start to decline (at a user specified rate) when the ratio of cumulative production to initial resource equals a user specified fraction.

Gas (plus lease condensate) production is calculated based on gas resource, and oil (plus associated gas) production is calculated based on the oil resource. Lease condensate production is separated from the gas production using the user specified condensate yield. Likewise, associated-dissolved gas production is separated from the oil production using the user specified associated gas-to-oil ratio. Associated-dissolved gas production is then tracked separately from the nonassociated gas production throughout the projection. Lease condensate production is added to crude oil production and is not tracked separately.

Figure 3-3. Undiscovered Field Production Profile



Source: ICF Consulting

Field Abandonment

All wells in a field are assumed to be shut-in when the net revenue from the field is less than total State and Federal taxes. Net revenue is total revenue from production less royalties, operating costs, transportation costs, and severance taxes.

Discovered Undeveloped Fields Component

Announced discoveries that have not been brought into production by 2002 are included in this component of the OOGSS. The data required for these fields include location, field size class, gas percentage of BOE resource, condensate yield, gas to oil ratio, start year of production, initial production rate, fraction produced before decline, and hyperbolic decline parameters. The BOE resource for each field corresponds to the field size class as specified in Table 3-3.

The number of development wells is the same as that of an undiscovered field in the same water depth and of the same field size class (Equation 3-13). The production profile is also the same as that of an undiscovered field (Figure 3-3).

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2009 are shown in Table 3-8. A field that is announced as an oil field is assumed to be 100 percent oil and a field that is announced as a gas field is assumed to be 100 percent gas. If a field is expected to produce both oil and gas, 70 percent is assumed to be oil and 30 percent is assumed to be gas.

Producing Fields Component

A separate database is used to track currently producing fields. The data required for each producing field include location, field size class, field type (oil or gas), total recoverable resources, historical production (1990-2002), and hyperbolic decline parameters.

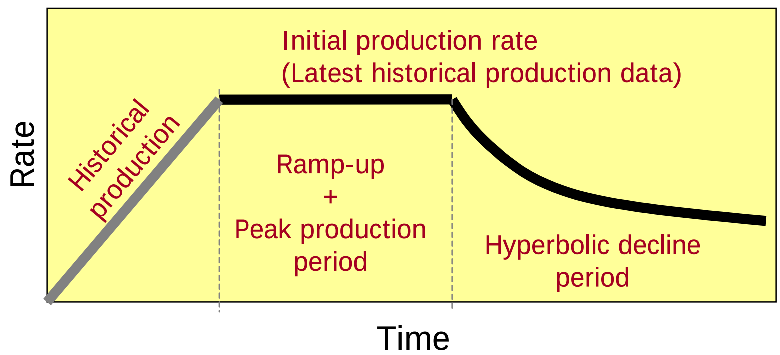
Projected production from the currently producing fields will continue to decline if, historically, production from the field is declining (Figure 3-4). Otherwise, production is held constant for a period of time equal to the sum of the specified number ramp-up years and number of years at peak production after which it will decline (Figure 3-5). The model assumes that production will decline according to a hyperbolic decline curve until the economic limit is achieved and the field is abandoned. Typical production profile data are shown in Table 3-9. Associated-dissolved gas and lease condensate production are determined the same way as in the undiscovered field component.

Table 3-8. Assumed Size and Initial Production Year of Major Announced Deepwater Discoveries

Field/Project Name	Block	Water Depth (feet)	Year of Discovery	Field Size Class	Field Size (MMBoe)	Start Year of Production
Great White	AC857	8717	2002	14	372	2010
Telemark	AT063	4457	2000	12	89	2010
Ozona	GB515	3000	2008	12	89	2011
West Tonga	GC726	4674	2007	12	89	2011
Gladden	MC800	3116	2008	12	89	2011
Pony	GC468	3497	2006	13	182	2013
Knotty Head	GC512	3557	2005	15	691	2013
Puma	GC823	4129	2003	14	372	2013
Big Foot	WR029	5235	2005	12	89	2013
Cascade	WR206	8143	2002	14	372	2013
Chinook	WR469	8831	2003	14	372	2013
Pyrenees	GB293	2100	2009	12	89	2014
Kaskida	KC292	5860	2006	15	691	2014
Appaloosa	MC503	2805	2008	14	372	2014
Jack	WR759	6963	2004	14	372	2014
Samurai	GC432	3400	2009	12	89	2015
Wide Berth	GC490	3700	2009	12	89	2015
Manny	MC199	2478	2010	13	182	2015
Kodiak	MC771	4986	2008	15	691	2015
St. Malo	WR678	7036	2003	14	372	2015
Mission Deep	GC955	7300	2006	13	182	2016
Tiber	KC102	4132	2009	16	1419	2016
Vito	MC984	4038	2009	13	182	2016
Stones	WR508	9556	2005	12	89	2016
Heidelberg	GB859	5000	2009	13	182	2017
Freedom	MC948	6095	2008	15	691	2017
Shenandoah	WR052	5750	2009	13	182	2017
Buckskin	KC872	6920	2009	13	182	2018
Julia	WR627	7087	2007	12	89	2018
Vicksburg	DC353	7457	2009	14	372	2019
Lucius	KC875	7168	2009	13	182	2019

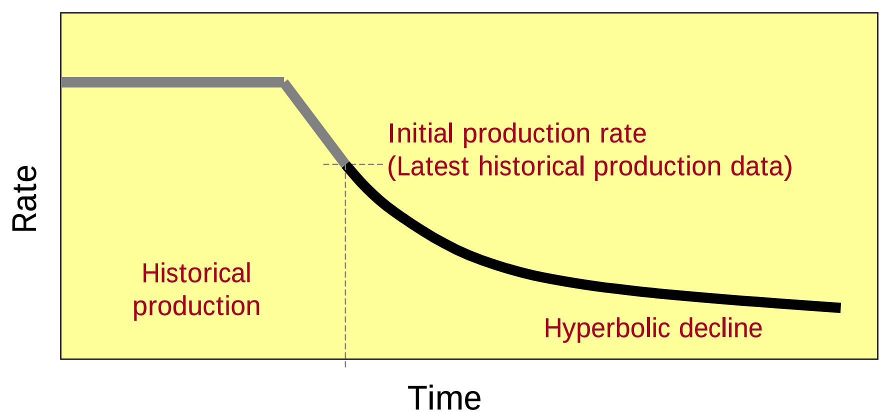
Source: U.S. Energy Information Administration, Energy Analysis, Office of Petroleum, Gas, and Biofuels Analysis

Figure 3-4. Production Profile for Producing Fields - Constant Production Case



Source: ICF Consulting

Figure 3-5. Production Profile for Producing Fields - Declining Production Case



Source: ICF Consulting

Table 3-9. Production Profile Data for Oil & Gas Producing Fields

	Crude Oil						Natural Gas					
	FSC 2 - 10			FSC 11 – 17			FSC 2 - 10			FSC 11 - 17		
Region	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate	Ramp-up (years)	At Peak (years)	Initial Decline Rate
Shallow GOM	2	2	0.15	3	3	0.10	2	1	0.20	3	2	0.10
Deep GOM	2	2	0.20	2	3	0.15	2	2	0.25	3	2	0.20
Atlantic	2	2	0.20	3	3	0.20	2	1	0.25	3	2	0.20
Pacific	2	2	0.10	3	2	0.10	2	1	0.20	3	2	0.20

FSC = Field Size Class
Source: ICF Consulting

Generation of Supply Curves

As mentioned earlier, the OOGSS does not determine the actual volume of crude oil and nonassociated natural gas produced in a given projection year but rather provides the parameters for the short-term supply functions used to determine regional supply and demand market equilibration. For each year, t, and offshore region, r, the OGSM calculates the stock of proved reserves at the beginning of year t+1 and the expected production-to-reserves (PR) ratio for year t+1 as follows.

The volume of proved reserves in any year is calculated as

$$RESOFF_{r,k,t+1} = RESOFF_{r,k,t} - PRDOFF_{r,k,t} + NRDOFF_{r,k,t} + REVOFF_{r,k,t} \quad (3\text{-}17)$$

where

RESOFF	=	beginning- of-year reserves
PRDOFF	=	production
NRDOFF	=	new reserve discoveries
REVOFF	=	reserve extensions, revisions, and adjustments
r	=	region (1=Atlantic, 2=Pacific, 3=GOM)
k	=	fuel type (1=oil; 2=nonassociated gas)
t	=	year.

Expected production, EXPRDOFF, is the sum of the field level production determined in the undiscovered fields component, the discovered, undeveloped fields component, and the producing field component. The volume of crude oil production (including lease condensate), PRDOFF, passed to the PMM is equal to EXPRDOFF. Nonassociated natural gas production in year t is the market equilibrated volume passed to the OGSM from the NGTDM.

Reserves are added through new field discoveries as well as delineation and developmental drilling. Each newly discovered field not only adds proved reserves but also a much larger amount of inferred reserves. The allocation between proved and inferred reserves is based on historical reserves growth statistics provided by the Minerals Management Service. Specifically,

$$NRDOFF_{r,k,t} = NFDISC_{r,k,t-1} * \left(\frac{1}{RSVGRO_k}\right) \quad (3\text{-}18)$$

$$NIRDOFF_{r,k,t} = NFDISC_{r,k,t-1} * \left(1 - \frac{1}{RSVGRO_k}\right) \quad (3\text{-}19)$$

where

NRDOFF	=	new reserve discovery
NIRDOFF	=	new inferred reserve additions
NFDISC	=	new field discoveries
RSVGRO	=	reserves growth factor (8.2738 for oil and 5.9612 for gas)
r	=	region (1=Atlantic, 2=Pacific, 3=GOM)
k	=	fuel type (1=oil; 2=gas)

t = year.

Reserves are converted from inferred to proved with the drilling of other exploratory (or delineation) wells and developmental wells. Since the expected offshore PR ratio is assumed to remain constant at the last historical value, the reserves needed to support the total expected production, EXPRDOFF, can be calculated by dividing EXPRDOFF by the PR ratio. Solving Equation 3-1 for $REVOFF_{r,k,t}$ and writing

gives

$$REVOFF_{r,k,t} = \frac{EXPRDOFF_{r,k,t+1}}{PR_{r,k}} + PRDOFF_{r,k,t} - RESOFF_{r,k,t} - NRDOFF_{r,k,t} \tag{3-20}$$

The remaining proved reserves, inferred reserves, and undiscovered resources are tracked throughout the projection period to ensure that production from offshore sources does not exceed the assumed resource base. Field level associated-dissolved gas is summed to the regional level and passed to the NGTDM.

Advanced Technology Impacts

Advances in technology for the various activities associated with crude oil and natural gas exploration, development, and production can have a profound impact on the costs associated with these activities. The OOGSS has been designed to give due consideration to the effect of advances in technology that may occur in the future. The specific technology levers and values are presented in Table 3-10.

Table 3-10. Offshore Exploration and Production Technology Levers

Technology Lever	Total Improvement (percent)	Number of Years
Exploration success rates	30	30
Delay to commence first exploration and between exploration	15	30
Exploration & development drilling costs	30	30
Operating cost	30	30
Time to construct production facility	15	30
Production facility construction costs	30	30
Initial constant production rate	15	30
Decline rate	0	30

Source: ICF Consulting

Appendix 3.A. Offshore Data Inventory

VARIABLES				
Variable Name				
Code	Text	Description	Unit	Classification
ADVLTXOFF	PRODTAX	Offshore ad valorem tax rates	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CPRDOFF	COPRD	Offshore coproduct rate	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CUMDISC	DiscoveredFields	Cumulative number of dicovered offshore fields	NA	Offshore evaluation unit: Field size class
CUMNFW	CumNFW	Cumulative number of new fields wildcats drilled	NA	Offshore evaluation unit: Field size class
CURPRROFF	omega	Offshore initial P/R ratios	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
CURRESOFF	R	Offshore initial reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
DECLOFF	--	Offshore decline rates	Fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
DEVLCOST	DevelopmentDrilling Cost	Development drilling cost	$ per well	Offshore evaluation unit
DRILLOFF	DRILL	Offshore drilling cost	1987$	4 Lower 48 offshore subregions
DRYOFF	DRY	Offshore dry hole cost	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions
DVWELLOFF	--	Offshore development project drilling schedules	wells per year	4 Lower 48 offshore subregions; Fuel (oil, gas)
ELASTOFF	--	Offshore production elasticity values	Fraction	4 Lower 48 offshore subregions
EXPLCOST	ExplorationDrillingC osts	Exploration well drilling cost	$ per wells	Offshore evaluation unit
EXWELLOFF	--	Offshore exploratory project drilling schedules	wells per year	4 Lower 48 offshore subregions
FLOWOFF	--	Offshore flow rates	bls, MCF per year	4 Lower 48 offshore subregions; Fuel (oil, gas)
FRMINOFF	FRMIN	Offshore minimum exploratory well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR1OFF	FR1	Offshore new field wildcat well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR2OFF	FR3	Offshore developmental well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
FR3OFF	FR2	Offshore other exploratory well finding rate	MMB BCF per well	4 Lower 48 offshore subregions; Fuel (oil, gas)
HISTPRROFF	--	Offshore historical P/R ratios	fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
HISTRESOFF	--	Offshore historical beginning-of-year reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
INFRSVOFF	I	Offshore inferred reserves	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
KAPFRCOFF	EXKAP	Offshore drill costs that are tangible & must be depreciated	fraction	Class (exploratory, developmental)
KAPSPNDOFF	KAP	Offshore other capital expenditures	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions
LEASOFF	EQUIP	Offshore lease equipment cost	1987$ per project	Class (exploratory, developmental); 4 Lower 48 offshore subregions
NDEVWLS	DevelopmentWells	Number of development wells drilled	NA	Offshore evaluation unit
NFWCOSTOFF	COSTEXP	Offshore new field wildcat cost	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions

VARIABLES				
Variable Name				
Code	Text	Description	Unit	Classification
NFWELLOFF	--	Offshore exploratory and developmental project drilling schedules	wells per project per year	Class (exploratory, developmental); r=1
NIRDOFF	NIRDOFF	Offshore new inferred reserves	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
NRDOFF	NRDOFF	Offshore new reserve discoveries	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
OPEROFF	OPCOST	Offshore operating cost	1987$ per well per year	Class (exploratory, developmental); 4 Lower 48 offshore subregions
OPRCOST	OperatingCost	Operating cost	$ per well	Offshore evaluation unit
PFCOST	StructureCost	Offshore production facility cost	$ per structure	Offshore evaluation unit
PRJOFF	N	Offshore project life	Years	Fuel (oil, gas)
RCPRDOFF	M	Offshore recovery period intangible & tangible drill cost	Years	Lower 48 Offshore
RESOFF	RESOFF	Offshore reserves	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
REVOFF	REVOFF	Offshore reserve revisions	Oil-MMB per well Gas-BCF per well	Offshore region; Offshore fuel(oil,gas)
SC	Γ	Search coefficient for discovery model	Fraction	Offshore evaluation unit: Field size class
SEVTXOFF	PRODTAX	Offshore severance tax rates	fraction	4 Lower 48 offshore subregions; Fuel (oil, gas)
SROFF	SR	Offshore drilling success rates	fraction	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
STTXOFF	STRT	State tax rates	fraction	4 Lower 48 offshore subregions
TECHOFF	TECH	Offshore technology factors applied to costs	fraction	Lower 48 Offshore
TRANSOFF	TRANS	Offshore expected transportation costs	NA	4 Lower 48 offshore subregions; Fuel (oil, gas)
UNRESOFF	Q	Offshore undiscovered resources	MMB BCF	4 Lower 48 offshore subregions; Fuel (oil, gas)
WDCFOFFIRKLAG	--	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
WDCFOFFIRLAG	--	1989 offshore regional exploration & development weighted DCFs	1987$	Class (exploratory, developmental); 4 Lower 48 offshore subregions;
WDCFOFFLAG	--	1989 offshore exploration & development weighted DCFs	1987$	Class (exploratory, developmental)
WELLAGOFF	WELLSOFF	1989 offshore wells drilled	Wells per year	Class (exploratory, developmental); 4 Lower 48 offshore subregions; Fuel (oil, gas)
XDCKAPOFF	XDCKAP	Offshore intangible drill costs that must be depreciated	fraction	NA

PARAMETERS		
Parameter	Description	Value
nREG	Region ID (1: CENTRAL & WESTERN GOM; 2: EASTERN GOM; 3: ATLANTIC; 4: PACIFIC)	4
nPA	Planning Area ID (1: WESTERN GOM; 2: CENTRAL GOM; 3: EASTERN GOM; 4: NORTH ATLANTIC; 5: MID ATLANTIC; 6: SOUTH ATLANTIC; 7: FLORIDA STRAITS; 8: PACIFIC; NORTHWEST; 9: CENTRAL CALIFORNIA; 10: SANTA BARBARA - VENTURA BASIN; 11: LOS ANGELES BASIN; 12: INNER BORDERLAND; 13: OUTER BORDERLAND)	13
ntEU	Total number of evaluation units (43)	43
nMaxEU	Maximum number of EU in a PA (6)	6
TOTFLD	Total number of evaluation units	3600
nANN	Total number of announce discoveries	127

PARAMETERS		
Parameter	**Description**	**Value**
nPRD	Total number of producing fields	1132
nRIGTYP	Rig Type (1: JACK-UP 0-1500; 2: JACK-UP 0-1500 (Deep Drilling); 3: SUBMERSIBLE 0-1500; 4: SEMI-SUBMERSIBLE 1500-5000; 5: SEMI-SUBMERSIBLE 5000-7500; 6: SEMI-SUBMERSIBLE 7500-10000; 7: DRILL SHIP 5000-7500; 8: DRILL SHIP 7500-10000)	8
nPFTYP	Production facility type (1: FIXED PLATFORM (FP); 2: COMPLIANT TOWER (CT); 3: TENSION LEG PLATFORM (TLP); 4: FLOATING PRODUCTION SYSTEM (FPS); 5: SPAR; 6: FLOATING PRODUCTION STORAGE & OFFLOADING (FPSO); 7: SUBSEA SYSTEM (SS))	7
nPFWDR	Production facility water depth range (1: 0 - 656 FEET; 2: 656 - 2625 FEET; 3: 2625 - 5249 FEET; 4: 5249 - 7874 FEET; 5: 7874 - 9000 FEET)	5
NSLTIdx	Number of platform slot data points	8
NPFWD	Number of production facility water depth data points	15
NPLTDD	Number of platform water depth data points	17
NOPFWD	Number of other production facitlity water depth data points	11
NCSTWD	Number of water depth data points for production facility costs	39
NDRLWD	Number of water depth data points for well costs	15
NWLDEP	Number of well depth data points	30
TRNPPLNCSTNDIAM	Number of pipeline diameter data points	19
MAXNFIELDS	Maximum number of fields for a project/prospect	10
nMAXPRJ	Maximum number of projects to evaluate per year	500
PRJLIFE	Maximum project life in years	10

INPUT DATA			
Variable	**Description**	**Unit**	**Source**
ann_EU	Announced discoveries - Evaluation unit name	-	PGBA
ann_FAC	Announced discoveries - Type of production facility	-	BOEMRE
ann_FN	Announced discoveries - Field name	-	PGBA
ann_FSC	Announced discoveries - Field size class	integer	BOEMRE
ann_OG	Announced discoveries - fuel type	-	BOEMRE
ann_PRDSTYR	Announced discoveries - Start year of production	integer	BOEMRE
ann_WD	Announced discoveries - Water depth	feet	BOEMRE
ann_WL	Announced discoveries - Number of wells	integer	BOEMRE
ann_YRDISC	Announced discoveries - Year of discovery	integer	BOEMRE
beg_rsva	AD gas reserves	bcf	calculated in model
BOEtoMcf	BOE to Mcf conversion	Mcf/BOE	ICF
chgDrlCstOil	Change of Drilling Costs as a Function of Oil Prices	fraction	ICF
chgOpCstOil	Change of Operating Costs as a Function of Oil Prices	fraction	ICF
chgPFCstOil	Change of Production facility Costs as a Function of Oil Prices	fraction	ICF
cndYld	Condensate yield by PA, EU	Bbl/mmcf	BOEMRE
cstCap	Cost of capital	percent	BOEMRE
dDpth	Drilling depth by PA, EU, FSC	feet	BOEMRE
deprSch	Depreciation schedule (8 year schedule)	fraction	BOEMRE
devCmplCst	Completion costs by region, completion type (1=Single, 2=Dual), water depth range (1=0-3000Ft, 2=>3000Ft), drilling depth index	million 2003 dollars	BOEMRE
devDrlCst	Mean development well drilling costs by region, water depth index, drilling depth index	million 2003 dollars	BOEMRE
devDrlDly24	Maximum number of development wells drilled from a 24-slot PF by drilling depth index	Wells/PF/year	ICF
devDrlDlyOth	Maximum number of development wells drilled for other PF by PF type, water depth index	Wells/field/year	ICF

INPUT DATA			
Variable	Description	Unit	Source
devOprCst	Operating costs by region, water depth range (1=0-3000Ft, 2=>3000Ft), drilling depth index	2003 $/well/year	BOEMRE
devTangFrc	Development Wells Tangible Fraction	fraction	ICF
dNRR	Number of discovered producing fields by PA, EU, FSC	integer	BOEMRE
Drillcap	Drilling Capacity	wells/year/rig	ICF
duNRR	Number of discovered/undeveloped fields by PA, EU, FSC	integer	ICF
EUID	Evaluation unit ID	integer	ICF
EUname	Names of evaluation units by PA	integer	ICF
EUPA	Evaluation unit to planning area x-walk by EU_Total	integer	ICF
exp1stDly	Delay before commencing first exploration by PA, EU	number of years	ICF
exp2ndDly	Total time (Years) to explore and appraise a field by PA, EU	number of years	ICF
expDrlCst	Mean Exploratory Well Costs by region, water depth index, drilling depth index	million 2003 dollars	BOEMRE
expDrlDays	Drilling days/well by rig type	number of days/well	ICF
expSucRate	Exploration success rate by PA, EU, FSC	fraction	ICF
ExpTangFrc	Exploration and Delineation Wells Tangible Fraction	fraction	ICF
fedTaxRate	Federal Tax Rate	percent	ICF
fldExpRate	Maximum Field Exploration Rate	percent	ICF
gasprice	Gas wellhead price by region	2003$/mcf	NGTDM
gasSevTaxPrd	Gas production severance tax	2003$/mcf	ICF
gasSevTaxRate	Gas severance tax rate	percent	ICF
GOprop	Gas proportion of hydrocarbon resource by PA, EU	fraction	ICF
GOR	Gas-to-Oil ratio (Scf/Bbl) by PA, EU	Scf/Bbl	ICF
GORCutOff	GOR cutoff for oil/gas field determination	-	ICF
gRGCGF	Gas Cumulative Growth Factor (CGF) for gas reserve growth calculation by year index	-	BOEMRE
levDelWls	Exploration drilling technology (reduces number of delineation wells to justify development	percent	PGBA
levDrlCst	Drilling costs R&D impact (reduces exploration and development drilling costs)	percent	PGBA
levExpDly	Pricing impact on drilling delays (reduces delays to commence first exploration and between exploration	percent	PGBA
levExpSucRate	Seismic technology (increase exploration success rate)	percent	PGBA
levOprCst	Operating costs R&D impact (reduces operating costs)	percent	PGBA
levPfCst	Production facility cost R&D impact (reduces production facility construction costs	percent	PGBA
levPfDly	Production facility design, fabrication and installation technology (reduces time to construct production facility)	percent	PGBA
levPrdPerf1	Completion technology 1 (increases initial constant production facility)	percent	PGBA
levPrdPerf2	Completion technology 2 (reduces decile rates)	percent	PGBA
nDelWls	Number of delineation wells to justify a production facility by PA, EU, FSC	integer	ICF
nDevWls	Maximum number of development wells by PA, EU, FSC	integer	ICF
nEU	Number of evaluation units in each PA	integer	ICF
nmEU	Names of evaluation units by PA	-	ICF
nmPA	Names of planning areas by PA	-	ICF
nmPF	Name of production facility and subsea-system by PF type index	-	ICF
nmReg	Names of regions by region	-	ICF
ndiroff	Additions to inferred reserves by region and fuel type	oil: MBbls; gas: Bcf	calculated in model
nrdoff	New reserve discoveries by region and fuel type	oil: Mbbls; gas: Bcf	calculated in model
nRigs	Number of rigs by rig type	integer	ICF

INPUT DATA			
Variable	Description	Unit	Source
nRigWlsCap	Number of well drilling capacity (Wells/Rig)	wells/rig	ICF
nRigWlsUtl	Number of wells drilled (Wells/Rig)	wells/rig	ICF
nSlt	Number of slots by # of slots index	integer	ICF
oilPrcCstTbl	Oil price for cost tables	2003$/Bbl	ICF
oilprice	Oil wellhead price by region	2003$/Bbl	PMM
oilSevTaxPrd	Oil production severance tax	2003$/Bbl	ICF
oilSevTaxRate	Oil severance tax rate	percent	ICF
oRGCGF	Oil Cumulative Growth Factor (CGF) for oil reserve growth calculation by year index	fraction	BOEMRE
paid	Planning area ID	integer	ICF
PAname	Names of planning areas by PA	-	ICF
pfBldDly1	Delay for production facility design, fabrication, and installation (by water depth index, PF type index, # of slots index (0 for non platform)	number of years	ICF
pfBldDly2	Delay between production facility construction by water depth index	number of years	ICF
pfCst	Mean Production Facility Costs in by region, PF type, water depth index, # of slots index (0 for non-platform)	million 2003 $	BOEMRE
pfCstFrc	Production facility cost fraction matrix by year index, year index	fraction	ICF
pfMaxNFld	Maximum number of fields in a project by project option	integer	ICF
pfMaxNWls	Maximum number of wells sharing a flowline by project option	integer	ICF
pfMinNFld	Minimum number of fields in a project by project option	integer	ICF
pfOptFlg	Production facility option flag by water depth range index, FSC	-	ICF
pfTangFrc	Production Facility Tangible Fraction	fraction	ICF
pfTypFlg	Production facility type flag by water depth range index, PF type index	-	ICF
platform	Flag for platform production facility	-	ICF
prd_DEPTH	Producing fields - Total drilling depth	feet	BOEMRE
prd_EU	Producing fields - Evaluation unit name	-	ICF
prd_FLAG	Producing fields - Production decline flag	-	ICF
prd_FN	Producing fields - Field name	-	BOEMRE
prd_ID	Producing fields - BOEMRE field ID	-	BOEMRE
prd_OG	Producing fields - Fuel type	-	BOEMRE
prd_YRDISC	Producing fields - Year of discovery	year	BOEMRE
prdDGasDecRatei	Initial gas decline rate by PA, EU, FSC range index	fraction/year	ICF
prdDGasHyp	Gas hyperbolic decline coefficient by PA, EU, FSC range index	fraction	ICF
prdDOilDecRatei	Initial oil decline rate by PA, EU,	fraction/year	ICF
prdDOilHyp	Oil hyperbolic decline coefficient by PA, EU, FSC range index	fraction	ICF
prdDYrPeakGas	Years at peak production for gas by PA, EU, FSC, range index	number of years	ICF
prdDYrPeakOil	Years at peak production for oil by PA, EU, FSC, range index	number of years	ICF
prdDYrRampUpGas	Years to ramp up for gas production by PA, EU, FSC range index	number of years	ICF
prdDYrRampUpOil	Years to ramp up for oil production by PA, EU, FSC range index	number of years	ICF
prdGasDecRatei	Initial gas decline rate by PA, EU	fraction/year	ICF
prdGasFrc	Fraction of gas produced before decline by PA, EU	fraction	ICF
prdGasHyp	Gas hyperbolic decline coefficient by PA, EU	fraction	ICF
prdGasRatei	Initial gas production (Mcf/Day/Well) by PA, EU	Mcf/day/well	ICF
PR	Expected production to reserves ratio by fuel typ	fraction	PGBA
prdoff	Expected production by fuel type	oil:MBbls; gas: Bcf	calculated in model
prdOilDecRatei	Initial oil decline rate by PA, EU	fraction/year	ICF
prdOilFrc	Fraction of oil produced before decline by PA, EU	fraction	ICF

INPUT DATA			
Variable	Description	Unit	Source
prdOilHyp	Oil hyperbolic decline coefficient by PA, EU	fraction	ICF
prdOilRatei	Initial oil production (Bbl/Day/Well) by PA, EU	Bbl/day/well	ICF
prod	Producing fields - annual production by fuel type	oil:MBbls; gas:Mmcf	BOEMRE
prod_asg	AD gas production	bcf	calculated in model
revoff	Extensions, revisions, and adjustments by fuel type	oil:MBbls; gas:Bcf	
rigBldRatMax	Maximum Rig Build Rate by rig type	percent	ICF
rigIncrMin	Minimum Rig Increment by rig type	integer	ICF
RigUtil	Number of wells drilled	wells/rig	ICF
rigUtilTarget	Target Rig Utilization by rig type	percent	ICF
royRateD	Royalty rate for discovered fields by PA, EU, FSC	fraction	BOEMRE
royRateU	Royalty rate for undiscovered fields by PA, EU, FSC	fraction	BOEMRE
stTaxRate	Federal Tax Rate by PA, EU	percent	ICF
trnFlowLineLen	Flowline length by PA, EU	Miles/prospect	ICF
trnPpDiam	Oil pipeline diameter by PA, EU	inches	ICF
trnPplnCst	Pipeline cost by region, pipe diameter index, water depth index	million 2003 $/mile	BOEMRE
trnTrfGas	Gas pipeline tariff ($/Mcf) by PA, EU	2003 $/Bbl	ICF
trnTrfOil	Oil pipeline tariff ($/Bbl) by PA, EU	2003 $/Bbl	ICF
uNRR	Number of undiscovered fields by PA, EU, FSC	integer	calculated in model
vMax	Maximum MMBOE of FSC	MMBOE	BOEMRE
vMean	Geometric mean MMBOE of FSC	MMBOE	BOEMRE
vMin	Minimum MMBOE of FSC	MMBOE	BOEMRE
wDpth	Water depth by PA, EU, FSC	feet	BOEMRE
yrAvl	Year lease available by PA, EU	year	ICF
yrCstTbl	Year of cost tables	year	ICF
Sources: BOEMRE = Bureau of Ocean Energy Management, Regulation, and Enforcement (formerly the Minerals Management Service); ICF = ICF Consulting; PGBA = EIA, Office of Petroleum, Gas, and Biofuels Analysis			

4. Alaska Oil and Gas Supply Submodule

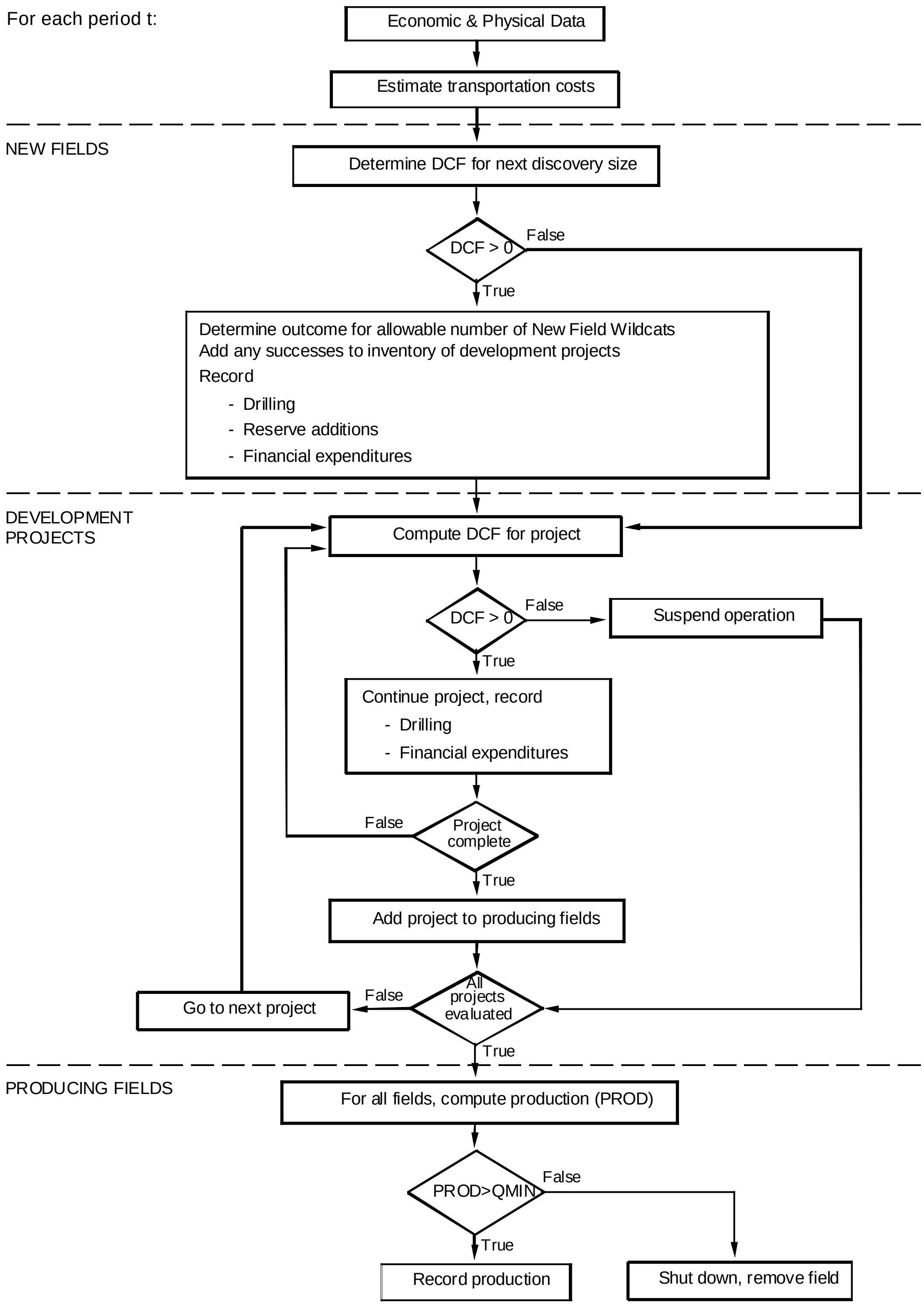
This section describes the structure for the Alaska Oil and Gas Supply Submodule (AOGSS). The AOGSS is designed to project field-specific oil production from the Onshore North Slope, Offshore North Slope, and Other Alaska areas (primarily the Cook Inlet area). The North Slope region encompasses the National Petroleum Reserve Alaska in the west, the State Lands in the middle, and the Arctic National Wildlife Refuge area in the east. This section provides an overview of the basic modeling approach, including a discussion of the discounted cash flow (DCF) method.

Alaska natural gas production is not projected by the AOGSS, but by Natural Gas Transmission and Distribution Module (NGTDM). The NGTDM projects Alaska gas consumption and whether an Alaska gas pipeline is projected to be built to carry Alaska North Slope gas into Canada and U.S. gas markets. As of January 1, 2009, Alaska was estimated to have 7.7 trillion cubic feet of proved reserves, 24.8 trillion cubic feet of inferred resources at existing fields (also known as field appreciation), and 257.5 trillion cubic feet of undiscovered resources, excluding the Arctic National Wildlife Refuge undiscovered gas resources. Over the long term, Alaska natural gas production is determined by and constrained by local consumption and by the capacity of a gas pipeline that might be built to serve Canada and U.S. lower-48 markets. The proven and inferred gas resources alone (i.e. 32.5 trillion cubic feet), plus known but undeveloped resources, are sufficient to satisfy at least 20 years of Alaska gas consumption and gas pipeline throughput. Moreover, large deposits of natural gas have been discovered (e.g., Point Thomson) but remain undeveloped due to a lack of access to gas consumption markets. Because Alaska natural gas production is best determined by projecting Alaska gas consumption and whether a gas pipeline is put into operation, the AOGSS does not attempt to project new gas field discoveries and their development or the declining production from existing fields.

AOGSS Overview

The AOGSS solely focuses on projecting the exploration and development of undiscovered oil resources, primarily with respect to the oil resources expected to be found onshore and offshore in North Alaska. The AOGSS is divided into three components: new field discoveries, development projects, and producing fields (Figure 4-1). Transportation costs are used in conjunction with the crude oil price to Southern California refineries to calculate an estimated wellhead (netback) oil price. A discounted cash flow (DCF) calculation is used to determine the economic viability of Alaskan drilling and production activities. Oil field investment decisions are modeled on the basis of discrete projects. The exploration, discovery, and development of new oil fields depend on the expected exploration success rate and new field profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and developmental projects, along with historical production patterns and announced plans for currently producing fields.

Figure 4-1. Flowchart of the Alaska Oil and Gas Supply Submodule



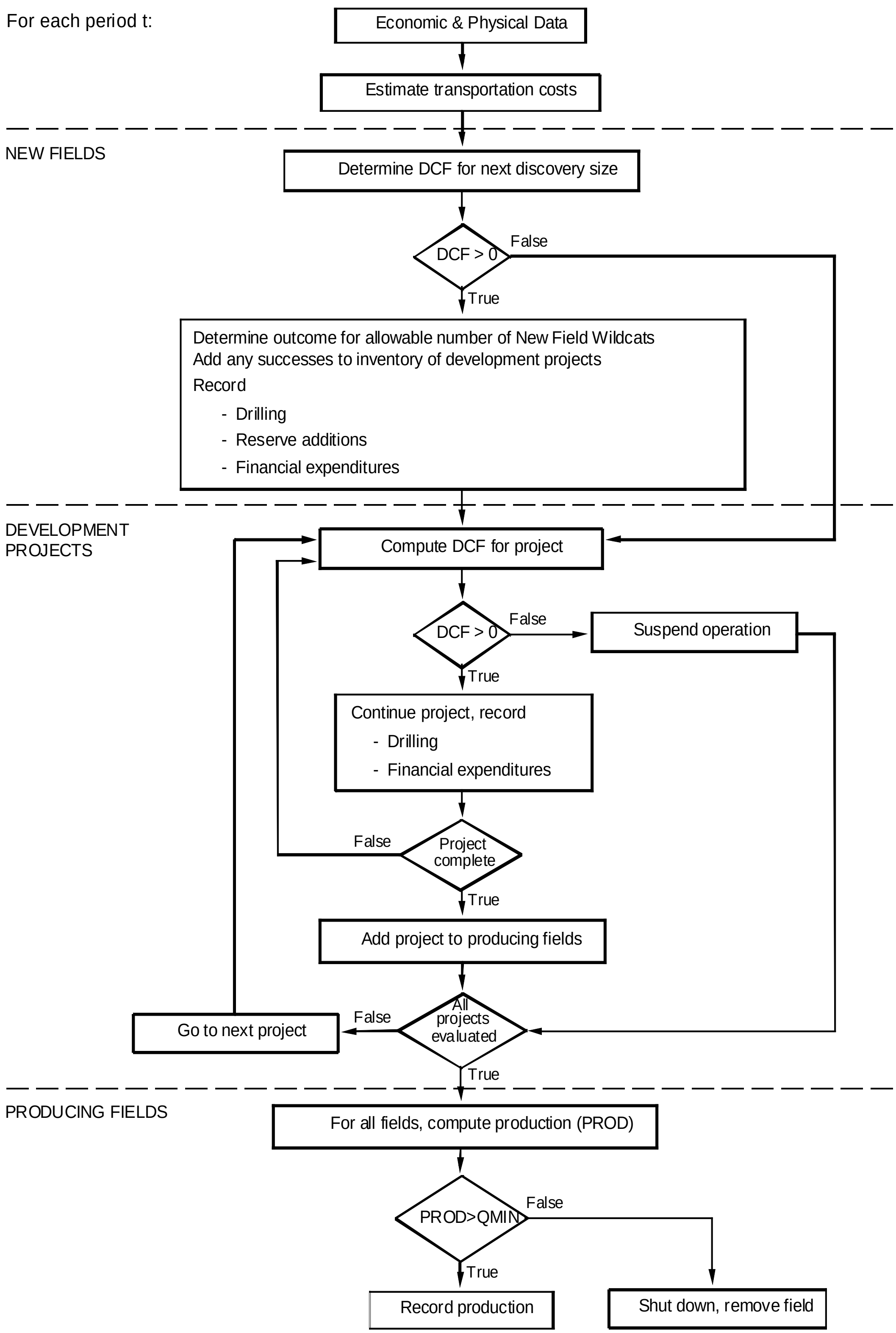
Calculation of Costs

Costs differ within the model for successful wells and dry holes. Costs are categorized functionally within the model as

- Drilling costs,
- Lease equipment costs, and
- Operating costs (including production facilities and general and administrative costs).

All costs in the model incorporate the estimated impact of environmental compliance. Environmental regulations that preclude a supply activity outright are reflected in other adjustments to the model. For example, environmental regulations that preclude drilling in certain locations within a region are modeled by reducing the recoverable resource estimates for that region.

Each cost function includes a variable that reflects the cost savings associated with technological improvements. As a result of technological improvements, average costs decline in real terms



relative to what they would otherwise be. The degree of technological improvement is a user specified option in the model. The equations used to estimate costs are similar to those used for the lower 48 but include cost elements that are specific to Alaska. For example, lease equipment includes gravel pads and ice roads.

Drilling Costs

Drilling costs are the expenditures incurred for drilling both successful wells and dry holes, and for equipping successful wells through the "Christmas tree," the valves and fittings assembled at the top of a well to control the fluid flow. Elements included in drilling costs are labor, material, supplies and direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals. Drilling costs for exploratory wells include costs of support equipment such as ice pads. Lease equipment required for production is included as a separate cost calculation and covers equipment installed on the lease downstream from the Christmas tree.

The average cost of drilling a well in any field located within region r in year t is given by:

$$DRILLCOST_{i,r,k,t} = DRILLCOST_{i,r,k,T_b} * (1 - TECH1) ** (t - T_b) \qquad (4\text{-}1)$$

where

i	=	well class (exploratory=1, developmental=2)
r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k	=	fuel type (oil=1, gas=2 - but not used)
t	=	forecast year
DRILLCOST	=	drilling costs
T_b	=	base year of the forecast
TECH1	=	annual decline in drilling costs due to improved technology.

The above function specifies that drilling costs decline at the annual rate specified by TECH1. Drilling costs are not modeled as a function of the drilling rig activity level as they are in the Onshore Lower 48 methodology. Drilling rigs and equipment are designed specifically for the harsh Arctic weather conditions. Once drilling rigs are moved up to Alaska and reconfigured for Arctic conditions, they typically remain in Alaska. Company drilling programs in Alaska are planned to operate at a relatively constant level of activity because of the limited number of drilling rigs and equipment available for use. Most Alaska oil rig activity pertains to drilling in-fill wells intended to slow the rate of production decline in the largest Alaska oil fields.

For the *Annual Energy Outlook 2011*, Alaska onshore and offshore drilling and completion costs were updated based on the American Petroleum Institute's (API), *2007 Joint Association Survey on Drilling Costs*, dated December 2008. Based on these API drilling and completion costs and earlier work performed by Advanced Resources International, Inc. in 2002, the following oil well drilling and completion costs were incorporated into the AOGSS database (Table 4.1).

Table 4.1
AOGSS Oil Well Drilling and Completion Costs
By Location and Category
In millions of 2007 dollars

	New Field Wildcat Wells	New Exploration Wells	Developmental Wells
	In millions of 2007 dollars		
Offshore North Slope	206	103	98
Onshore North Slope	150	75	57
South Alaska	73	59	37
	In millions of 1990 dollars		
Offshore North Slope	140	70	67
Onshore North Slope	102	51	39
South Alaska	50	40	25

Table 1 provides both 1990 and 2007 well drilling and completion cost data because the former are used within the context of calculating AOGSS discounted cash flows, while the latter are comparable to the current price environment.

Lease Equipment Costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a developed lease. Costs include: producing equipment, the gathering system, processing equipment (e.g., oil/gas/water separation), and production related infrastructure such as gravel pads. Producing equipment costs include tubing, pumping equipment. Gathering system costs consist of flowlines and manifolds. The lease equipment cost estimate for a new oil well is given by:

$$\mathrm{EQUIP}_{r,k,t} = \mathrm{EQUIP}_{r,k,t} * (1 - \mathrm{TECH2})^{r-T_b} \qquad (4\text{-}2)$$

where

r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k	=	fuel type (oil=1, gas=2 – not used)
t	=	forecast year
EQUIP	=	lease equipment costs
T_b	=	base year of the forecast
TECH2	=	annual decline in lease equipment costs due to improved technology.

Operating Costs

EIA operating cost data, which are reported on a per well basis for each region, include three main categories of costs: normal daily operations, surface maintenance, and subsurface maintenance. Normal daily operations are further broken down into supervision and overhead, labor, chemicals, fuel, water, and supplies. Surface maintenance accounts for all labor and materials necessary to keep the service equipment functioning efficiently and safely. Costs of stationary facilities, such as roads, also are included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

The estimated operating cost curve is:

$$OPCOST_{r,k,t} = OPCOST_{r,k,t} * (1 - TECH2)^{r - T_b} \tag{4-3}$$

where

r	=	region (Offshore North Slope = 1, Onshore North Slope = 2, Cook Inlet = 3)
k	=	fuel type (oil=1, gas=2 – not used)
t	=	forecast year
OPCOST	=	operating cost
T_b	=	base year of the forecast
TECH3	=	annual decline in operating costs due to improved technology.

Drilling costs, lease equipment costs, and operating costs are integral components of the following discounted cash flow analysis. These costs are assumed to be uniform across all fields within each of the three Alaskan regions.

Treatment of Costs in the Model for Income Tax Purposes

All costs are treated for income tax purposes as either expensed or capitalized. The tax treatment in the DCF reflects the applicable provisions for oil producers. The DCF assumptions are consistent with standard accounting methods and with assumptions used in similar modeling efforts. The following assumptions, reflecting current tax law, are used in the calculation of costs.

- All dry-hole costs are expensed.

- A portion of drilling costs for successful wells is expensed. The specific split between expensing and amortization is based on the tax code.

- Operating costs are expensed.

- All remaining successful field development costs are capitalized.

- The depletion allowance for tax purposes is not included in the model, because the current regulatory limitations for invoking this tax advantage are so restrictive as to be insignificant in the aggregate for future drilling decisions.

- Successful versus dry-hole cost estimates are based on historical success rates of successful versus dry-hole footage.

- Lease equipment for existing wells is in place before the first forecast year of the model.

Discounted Cash Flow Analysis

A discounted cash flow (DCF) calculation is used to determine the profitability of oil projects.[1] A positive DCF is necessary to initiate the development of a discovered oil field. With all else being equal, large oil fields are more profitable to develop than small and mid-size fields. In Alaska, where developing new oil fields is quite expensive, particularly in the Arctic, the profitable development of small and mid-size oil fields is generally contingent on the pre-existence of infrastructure that was paid for by the development of a nearby large field. Consequently, AOGSS assumes that the largest oil fields will be developed first, followed by the development of ever smaller oil fields. Whether these oil fields are developed, regardless of their size, is projected on the basis of the profitability index, which is measured as the ratio of the expected discounted cash flow to expected capital costs for a potential project.

A key variable in the DCF calculation is the oil transportation cost to southern California refineries. Transportation costs for Alaskan oil include both pipeline and tanker shipment costs. The oil transportation cost directly affects the expected revenues from the production of a field as follows:[2]

$$REV_{f,t} = Q_{f,t} * (MP_t - TRANS_t) \tag{4-4}$$

where

f	=	field
t	=	year
REV	=	expected revenues
Q	=	expected production volumes
MP	=	market price in the lower 48 states
TRANS	=	transportation cost.

The expected discounted cash flow associated with a potential oil project in field f at time t is given by

$$\begin{aligned} DCF_{f,t} = (&PVREV - PVROY - PVDRILLCOST - PVEQUIP - TRANSCAP \\ &- PVOPCOST - PVPRODTAX - PVSIT - PVFIT)_{f,t} \end{aligned} \tag{4-5}$$

where,

PVREV	=	present value of expected revenues

[1]See Appendix 3.A at the end of this chapter for a detailed discussion of the DCF methodology.

[2]This formulation assumes oil production only. It can be easily expanded to incorporate the sale of natural gas.

PVROY	=	present value of expected royalty payments
PVDRILLCOST	=	present value of all exploratory and developmental drilling expenditures
PVEQUIP	=	present value of expected lease equipment costs
TRANSCAP	=	cost of incremental transportation capacity
PVOPCOST	=	present value of operating costs
PVPRODTAX	=	present value of expected production taxes (ad valorem and severance taxes)
PVSIT	=	present value of expected state corporate income taxes
PVFIT	=	present value of expected federal corporate income taxes

The expected capital costs for the proposed field f located in region r are:

$$COST_{f,t} = (PVEXPCOST + PVDEVCOST + PVEQUIP + TRANSCAP)_{f,t} \tag{4-6}$$

where

PVEXPCOST	=	present value exploratory drilling costs
PVDEVCOST	=	present value developmental drilling costs
PVEQUIP	=	present value lease equipment costs
TRANSCAP	=	cost of incremental transportation capacity

The profitability indicator from developing the proposed field is therefore

$$PROF_{f,t} = \frac{DCF_{f,t}}{COST_{f,t}} \tag{4-7}$$

The model assumes that field with the highest positive PROF in time t is eligible for exploratory drilling in the same year. The profitability indices for Alaska also are passed to the basic framework module of the OGSM.

New Field Discovery

Development of estimated recoverable resources, which are expected to be in currently undiscovered fields, depends on the schedule for the conversion of resources from unproved to reserve status. The conversion of resources into field reserves requires both a successful new field wildcat well and a positive discounted cash flow of the costs relative to the revenues. The discovery procedure can be determined endogenously, based on exogenously determined data. The procedure requires the following exogenously determined data:

- new field wildcat success rate,
- any restrictions on the timing of drilling,
- the distribution of technically recoverable field sizes within each region.

The endogenous procedure generates:

- the new field wildcat wells drilled in any year,

- the set of individual fields to be discovered, specified with respect to size and location (relative to the 3 Alaska regions, i.e., offshore North Slope, onshore North Slope, and South-Central Alaska),

- an order for the discovery sequence, and

- a schedule for the discovery sequence.

The new field discovery procedure relies on the U.S. Geological Survey (USGS) and Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) respective estimates of onshore and offshore technically recoverable oil resources as translated into the expected field size distribution of undiscovered fields. These onshore and offshore field size distributions are used to determine the field size and order of discovery in the AOGSS exploration and discovery process. Thus, the AOGSS oil field discovery process is consistent with the expected geology with respect to expected aggregate resource base and the relative frequency of field sizes.

AOGSS assumes that the largest fields in a region are found first, followed by successively smaller fields. This assumption is based on the following observations: 1) the largest volume fields typically encompass the greatest areal extent, thereby raising the probability of finding a large field relative to finding a smaller field, 2) seismic technology is sophisticated enough to be able to determine the location of the largest geologic structures that might possibly hold oil, 3) producers have a financial incentive to develop the largest fields first both because of their higher inherent rate of return and because the largest fields can pay for the development of expensive infrastructure that affords the opportunity to develop the smaller fields using that same infrastructure, and 4) historically, North Slope and Cook Inlet field development has generally progressed from largest field to smallest field.

Starting with the AEO2011, onshore and offshore North Slope new field wildcat drilling activity is a function of West Texas Intermediate crude oil prices from 1977 through 2008, expressed in 2008 dollars. The new field wildcat exploration function was statistically estimated based on West Texas Intermdiate crude oil prices from 1977 through 2008 and on exploration well drilling data obtained from the Alaska Oil and Gas Conservation Commission (AOGCC) data files for the same period.[3] The North Slope wildcat exploration drilling parameters were estimated using ordinary least squares methodology.

$$NAK\_NFW_t = (0.13856 * IT\_WOP_t) + 3.77 \tag{4-8}$$

where

t	=	year
NAK_NFW_t	=	North Slope Alaska field wildcat exploration wells
IT_WOP_t	=	World oil price in 2008 dollars

[3] A number of alternative functional formulations were tested (e.g., using Alaska crude oil prices, lagged oil prices, etc.), yet none of the alternative formations resulted in statistically more significant relationships.

The summary statistics for the statistical estimation are as follows:

```
Dependent variable: NSEXPLORE
Current sample:  1 to 32
Number of observations:  32

       Mean of dep. var. = 9.81250      LM het. test = .064580 [.799]
  Std. dev. of dep. var. = 4.41725     Durbin-Watson = 2.04186 [<.594]
Sum of squared residuals = 347.747  Jarque-Bera test = .319848 [.852]
   Variance of residuals = 11.5916   Ramsey's RESET2 = .637229E-04 [.994]
Std. error of regression = 3.40464   F (zero slopes) = 22.1824 [.000]
               R-squared = .425094    Schwarz B.I.C. = 87.0436
      Adjusted R-squared = .405930    Log likelihood = -83.5778

           Estimated    Standard
Variable  Coefficient     Error       t-statistic   P-value
C         3.77029       1.41706       2.66065       [.012]
WTIPRICE  .138559       .029419       4.70982       [.000]
```

Because very few offshore North Slope wells have been drilled since 1977, within AOGSS, the total number of exploration wells drilled on the North Slope are shared between the onshore and offshore regions, with the wells being predominantly drilled onshore in the early years of the projections with progressively more wells drilled offshore, such that after 20 years 50 percent of the exploration wells are drilled onshore and 50 percent are drilled offshore.

Based on the AOGCC data for 1977 through 2008, the drilling of South-Central Alaska new field wildcat exploration wells was statistically unrelated to oil prices. On average, 3 exploration wells per year were drilled in South-Central Alaska over the 1977 through 2008 timeframe, regardless of prevailing oil prices. This result probably stems from the fact that most of the South-Central Alaska drilling activity is focused on natural gas rather than oil, and that natural gas prices are determined by the Regulatory Commission of Alaska rather than being "market driven." Consequently, AOGSS specifies that 3 exploration wells are drilled each year.

The execution of the above procedure can be modified to reflect restrictions on the timing of discovery for particular fields. Restrictions may be warranted for enhancements such as delays necessary for technological development needed prior to the recovery of relatively small accumulations or heavy oil deposits. State and Federal lease sale schedules could also restrict the earliest possible date for beginning the development of certain fields. This refinement is implemented by declaring a start date for possible exploration. For example, AOGSS specifies that if Federal leasing in the Arctic National Wildlife Refuge were permitted in 2011, then the earliest possible date at which an ANWR field could begin oil production would be in 2021.[4] Another example is the wide-scale development of the West Sak field that is being delayed until a technology can be developed that will enable the heavy, viscous crude oil of that field to be economically extracted.

[4]The earliest ANWR field is assumed to go into production 10 years after the first projection year; so the first field comes on line in 2020 for the *Annual Energy Outlook 2010* projections.   See also *Analysis of Crude Oil Production in the Arctic National Wildlife Refugee*, EIA, SR/OIAF/2008-03, (May 2008).

Development Projects

Development projects are those projects in which a successful new field wildcat has been drilled. As with the new field discovery process, the DCF calculation plays an important role in the timing of development and exploration of these multi-year projects.

Each model year, the DCF is calculated for each potential development project. Initially, the model assumes a drilling schedule determined by the user or by some set of specified rules. However, if the DCF for a given project is negative, then development of this project is suspended in the year in which the negative DCF occurs. The DCF for each project is evaluated in subsequent years for a positive value. The model assumes that development would resume when a positive DCF value is calculated.

Production from developing projects follows the generalized production profile developed for and described in previous work conducted by DOE staff.[5] The specific assumptions used in this work are as follows:

- a 2- to 4-year build-up period from initial production to the peak production rate,
- the peak production rate is sustained for 3 to 8 years, and
- after peak production, the production rate declines by 12 to 15 percent per year.

The production algorithm build-up and peak-rate period are based on the expected size of the undiscovered field, with larger fields having longer build-up and peak-rate periods than the smaller fields. The field production decline rates are also determined by the field size.

The pace of development and the ultimate number of wells drilled for a particular field is based on the historical field-level profile adjusted for field size and other characteristics of the field (e.g. API gravity.)

After all exploratory and developmental wells have been drilled for a given project, development of the project is complete. For this version of the AOGSS, no constraint is placed on the number of exploratory or developmental wells that can be drilled for any project. All completed projects are added to the inventory of producing fields.

Development fields include fields that have already been discovered but have not begun production. These fields include, for example, a series of expansion fields in both the Prudhoe Bay area, the National Petroleum Reserve - Alaska (NPRA), and for various offshore fields. For these fields, the starting date of production and their production rates were not determined by the discovery process outlined above, but are based on public announcements by the company(s) developing those fields.

[5] *Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment*, EIA (May 2000) and *Alaska Oil and Gas - Energy Wealth of Vanishing Opportunity?*, DOE/ID/0570-H1 (January 1991).

Producing Fields

Oil production from fields producing as of the initial projection year (e.g., Prudhoe Bay, Kuparuk, Lisburne, Endicott, and Milne Point) are based on historical production patterns, remaining estimated recovery, and announced development plans. The production decline rates of these fields are periodically recalibrated based on recent field-specific production rates.

Natural gas production from the North Slope for sale to end-use markets depends on the construction of a pipeline to transport natural gas to lower 48 markets.[6] North Slope natural gas production is determined by the carrying capacity of a natural gas pipeline to the lower 48.[7] The Prudhoe Bay Field is the largest known deposit of North Slope gas (24.5 Tcf)[8] and currently all of the gas produced from this field is re-injected to maximize oil production. Total known North Slope gas resources equal 35.4 Tcf.[9] Furthermore, the undiscovered onshore central North Slope and NPRA technically recoverable natural gas resource base are respectively estimated to be 33.3 Tcf[10] and 52.8 Tcf.[11] Collectively, these North Slope natural gas reserves and resources equal 121.5 Tcf, which would satisfy the 1.64 Tcf per year gas requirements of an Alaska gas pipeline for almost 75 years, well after the end of the *Annual Energy Outlook* projections. Consequently, North Slope natural gas resources, both discovered and undiscovered, are more than ample to supply natural gas to an Alaska gas pipeline during the *Annual Energy Outlook* projection period.

[6]Initial natural gas production from the North Slope for Lower 48 markets is affected by a delay reflecting a reasonable period for construction. Details of how this decision is made in NEMS are included in the Natural Gas Transmission and Distribution Module documentation.

[7] The determination of whether an Alaska gas pipeline is economically feasible is calculated within the Natural Gas Transmission and Distribution Model.

[8] *Alaska Oil and Gas Report 2009*, Alaska Department of Natural Resources, Division of Oil and Gas, Table I.I, page 8.

[9] Ibid.

[10] U.S. Geological Survey, *Oil and Gas Assessment of Central North Slope, Alaska, 2005*, Fact Sheet 2005-3043, April 2005, page 2 table – mean estimate total.

[11] U.S. Geological Survey, *2010 Updated Assessment of Undiscovered Oil and Gas Resources of the National Petroleum Reserve in Alaska (NPRA)*, Fact Sheet 2010-3102, October 2010, Table 1 – mean estimate total, page 4.

Appendix 4.A. Alaskan Data Inventory

Variable Name		Description	Unit	Classification	Source
Code	Text				
ANGTSMAX	--	ANGTS maximum flow	BCF/D	Alaska	NPC
ANGTSPRC	--	Minimum economic price for ANGTS start up	1987$/MCF	Alaska	NPC
ANGTSRES	--	ANGTS reserves	BCF	Alaska	NPC
ANGTSYR	--	Earliest start year for ANGTS flow	Year	NA	NPC
DECLPRO	--	Alaska decline rates for currently producing fields	Fraction	Field	OPNGBA
DEV_AK	--	Alaska drilling schedule for developmental wells	Wells per year	3 Alaska regions; Fuel (oil, gas)	OPNGBA
DRILLAK	DRILL	Alaska drilling cost (not including new field wildcats)	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	OPNGBA
DRLNFWAK	--	Alaska drilling cost of a new field wildcat	1990$/well	3 Alaska regions; Fuel (oil, gas)	OPNGBA
DRYAK	DRY	Alaska dry hole cost	1990$/hole	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	OPNGBA
EQUIPAK	EQUIP	Alaska lease equipment cost	1990$/well	Class (exploratory, developmental); 3 Alaska regions; Fuel (oil, gas)	USGS
EXP_AK	--	Alaska drilling schedule for other exploratory wells	wells per year	3 Alaska regions	OPNGBA
FACILAK	--	Alaska facility cost (oil field)	1990$/bls	Field size class	USGS
FSZCOAK	--	Alaska oil field size distributions	MMB	3 Alaska regions	USGS
FSZNGAK	--	Alaska gas field size distributions	BCF	3 Alaska regions	USGS
HISTPRDCO	--	Alaska historical crude oil production	MB/D	Field	AOGCC
KAPFRCAK	EXKAP	Alaska drill costs that are tangible & must be depreciated	fraction	Alaska	U.S. Tax Code
MAXPRO	--	Alaska maximum crude oil production	MB/D	Field	Announced Plans
NAK_NFW	--	Number of new field wildcat wells drilling in Northern AK	wells per year	NA	OPNGBA
NFW_AK	--	Alaska drilling schedule for new field wildcats	wells	NA	OPNGBA
PRJAK	n	Alaska oil project life	Years	Fuel (oil, gas)	OPNGBA
PROYR	--	Start year for known fields in Alaska	Year	Field	Announced Plans

Variable Name					
Code	Text	Description	Unit	Classification	Source
RCPRDAK	m	Alaska recovery period of intangible & tangible drill cost	Years	Alaska	U.S. Tax Code
RECRES	--	Alaska crude oil resources for known fields	MMB	Field	OFE, *Alaska Oil and Gas - Energy Wealth or Vanishing Opportunity*
ROYRT	ROYRT	Alaska royalty rate	fraction	Alaska	USGS
SEVTXAK	PRODTAX	Alaska severance tax rates	fraction	Alaska	USGS
SRAK	SR	Alaska drilling success rates	fraction	Alaska	OPNGBA
STTXAK	STRT	Alaska state tax rate	fraction	Alaska	USGS
TECHAK	TECH	Alaska technology factors	fraction	Alaska	OPNGBA
TRANSAK	TRANS	Alaska transportation cost	1990$	3 Alaska regions; Fuel (oil, gas)	OPNGBA
XDCKAPAK	XDCKAP	Alaska intangible drill costs that must be depreciated	fraction	Alaska	U.S. Tax Code

Source: National Petroleum Council (NPC), EIA Office of Petroleum, Natural Gas, & Biofuels Analysis (OPNGBA), United States Geologic Survey (USGS), Alaska Oil and Gas Conservation Commission (AOGCC)

5. Oil Shale Supply Submodule

Oil shale rock contains a hydrocarbon known as kerogen,[12] which can be processed into a synthetic crude oil (syncrude) by heating the rock. During the 1970s and early 1980s, petroleum companies conducted extensive research, often with the assistance of public funding, into the mining of oil shale rock and the chemical conversion of the kerogen into syncrude. The technologies and processes developed during that period are well understood and well documented with extensive technical data on demonstration plant costs and operational parameters, which were published in the professional literature. The oil shale supply submodule in OGSM relies extensively on this published technical data for providing the cost and operating parameters employed to model the "typical" oil shale syncrude production facility.

In the 1970s and 1980s, two engineering approaches to creating the oil shale syncrude were envisioned. In one approach, which the majority of the oil companies pursued, the producer mines the oil shale rock in underground mines. A surface facility the retorts the rock to create bitumen, which is then further processed into syncrude. Occidental Petroleum Corp. pursued the other approach known as "modified in-situ," in which some of the oil shale rock is mined in underground mines, while the remaining underground rock is "rubblized" using explosives to create large caverns filled with oil shale rock. The rubblized oil shale rock is then set on fire to heat the kerogen and convert it into bitumen, with the bitumen being pumped to the surface for further processing into syncrude. The modified in-situ approach was not widely pursued because the conversion of kerogen into bitumen could not be controlled with any precision and because the leaching of underground bitumen and other petroleum compounds might contaminate underground aquifers.

When oil prices dropped below $15 per barrel in the mid-1990s, demonstrating an abundance of conventional oil supply, oil shale petroleum production became untenable and project sponsors canceled their oil shale research and commercialization programs. Consequently, no commercial-scale oil shale production facilities were ever built or operated. Thus, the technical and economic feasibility of oil shale petroleum production remains untested and unproven.

In 1997, Shell Oil Company started testing a completely in-situ oil shale process, in which the oil shale rock is directly heated underground using electrical resistance heater wells, while petroleum products[13] are produced from separate production wells. The fully in-situ process has significant environmental and cost benefits relative to the other two approaches. The environmental benefits are lower water usage, no waste rock disposal, and the absence of hydrocarbon leaching from surface waste piles. As an example of the potential environmental impact on surface retorting, an industry using 25 gallon per ton oil shale rock to produce 2 million barrels per day would generate about 1.2 billion tons of waste rock per year, which is about 11 percent more than the weight of all the coal mined in the United States in 2010. Other advantages of the in-situ process include: 1) access to deeper oil shale resources, 2) greater oil and gas generated per acre because the process uses multiple oil shale seams within the resource column rather than just a single seam, and 3) direct production of petroleum products rather than

[12] Kerogen is a solid organic compound, which is also found in coal.
[13] Approximately, 30 percent naphtha, 30 percent jet fuel, 30 percent diesel, and 10 percent residual fuel oil.

a synthetic crude oil that requires more refinery processing. Lower production costs are expected for the in-situ approach because massive volumes of rock would not be moved, and because the drilling of heater wells, production wells, and freeze-wall wells can be done in a modular fashion, which allows for a streamlined manufacturing-like process. Personnel safety would be greater and accident liability lower. Moreover, the in-situ process reduces the capital risk, because it involves building self-contained modular production units that can be multiplied to reach a desired total production level. Although the technical and economic feasibility of the in-situ approach has not been commercially demonstrated, there is already a substantial body of evidence from field tests conducted by Shell Oil Co. that the in-situ process is technologically feasible.[14] The current Shell field research program is expected to conclude around the 2014 through 2017 timeframe with the construction of a small scale demonstration plant expected to begin shortly thereafter. The Oil Shale Supply Submodule (OSSS) assumes that the first commercial size oil shale plant cannot be built prior to 2017.

Given the inherent cost and environmental benefits of the in-situ approach, a number of other companies, such as Chevron and ExxonMobil are testing alternative in-situ oil shale techniques. Although small-scale mining and surface retorting of oil shale is currently being developed, by companies such as Red Leaf Resources, the large scale production of oil shale will most likely use the in-situ process. However, because in-situ oil shale projects have never been built, and because companies developing the in-situ process have not publicly released detailed technical parameters and cost estimates, the cost and operational parameters of such in-situ facilities is unknown. Consequently, the Oil Shale Supply Submodule (OSSS) relies on the project parameters and costs associated with the underground mining and surface retorting approach that were designed during the 1970s and 1980s. In this context, the underground mining and surface retorting facility parameters and costs are meant to be a surrogate for the in-situ oil shale facility that is more likely to be built. Although the in-situ process is expected to result in a lower cost oil shale product, this lower cost is somewhat mitigated by the fact that the underground mining and surface retorting processes developed in the 1970s and 1980s did not envision the strict environmental regulations that prevail today, and therefore embody an environmental compliance cost structure that is lower than what would be incurred today by a large-scale underground mining and surface retorting facility. Also, the high expected cost structure of the underground mining/surface retorting facility constrains the initiation of oil shale project production, which should be viewed as a more conservative approach to simulating the market penetration of in-situ oil projects. On the other hand, OSSS oil shale facility costs are reduced by 1 percent per year to reflect technological progress, especially with respect to the improvement of an in-situ oil shale process. Finally, public opposition to building any type of oil shale facility is likely to be great, regardless of the fact that the in-situ process is expected to be more environmentally benign than the predecessor technologies; the cost of building an in-situ oil shale facility is therefore likely to be considerably greater than would be determined strictly by the engineering parameters of such a facility.[15]

The Oil Shale Supply Submodule (OSSS) only represents economic decision making. In the absence of any existing commercial oil shale projects, it was impossible to determine the

[14] *See* "Shell's In-situ Conversion Process," a presentation by Harold Vinegar at the Colorado Energy Research Institute's 26th Oil Shale Symposium held on October 16 – 18, 2006 in Boulder, Colorado.

[15] Project delays due to public opposition can significantly increase project costs and reduce project rates of return.

potential environmental constraints and costs of producing oil on a large scale. Given the considerable technical and economic uncertainty of an oil shale industry based on an in-situ technology, and the infeasibility of the large-scale implementation of an underground mining/surface retorting technology, the oil shale syncrude production projected by the OSSS should be considered highly uncertain.

Given this uncertainty, the construction of commercial oil shale projects is constrained by a linear market penetration algorithm that restricts the oil production rate, which, at best, can reach a maximum of 2 million barrels per day by the end of a 40-year period after commercial oil shale facilities are deemed to be technologically feasible (starting in 2017). Whether domestic oil shale production actually reaches 2 million barrels per day at the end of the 40-year period depends on the relative profitability of oil shale facilities. If oil prices are too low to recover the weighted average cost of capital, no new facilities are built. However, if oil prices are sufficiently high to recover the cost of capital, then the rate of market penetration rises in direct proportion to facility profitability. So as oil prices rise and oil shale facility profitability increases, the model assumes that oil shale facilities are built in greater numbers, as dictated by the market penetration algorithm.

The 2 million barrel per day production limit is based on an assessment of what is feasible given both the oil shale resource base and potential environmental constraints.[16] The 40-year minimum market penetration timeframe is based on the observation that "…an oil shale production level of 1 million barrels per day is probably more than 20 years in the future…"[17] with a linear ramp-up to 2 million barrels per day equating to a 40-year minimum.

The actual rate of market penetration in the OSSS largely depends on projected oil prices, with low prices resulting in low rates of market penetration, and with the maximum penetration rate only occurring under high oil prices that result in high facility profitability. The development history of the Canadian oil sands industry is an analogous situation. The first commercial Canadian oil sands facility began operations in 1967; the second project started operation in 1978; and the third project initiated production in 2003.[18] So even though the Canadian oil sands resource base is vast, it took over 30 years before a significant number of new projects were announced. This slow penetration rate, however, was largely caused by both the low world oil prices that persisted from the mid-1980s through the 1990s and the lower cost of developing conventional crude oil supply.[19] The rise in oil prices that began in 2003 caused 17 new oil sands projects to be announced by year-end 2007.[20] Oil prices subsequently peaked in July 2008,

[16] *See* U.S. Department of Energy, "Strategic Significance of America's Oil Shale Resource," March 2004, Volume I, page 23 – which speaks of an "aggressive goal" of 2 million barrels per day by 2020; and Volume II, page 7 – which concludes that the water resources in the Upper Colorado River Basin are "more than enough to support a 2 million barrel/day oil shale industry…"

[17] Source: RAND Corporation, "Oil Shale Development in the United States – Prospects and Policy Issues," MG-414, 2005, Summary page xi.

[18] The owner/operator for each of the 3 initial oil sands projects were respectively Suncor, Syncrude, and Shell Canada.

[19] The first Canadian commercial oil sands facility started operations in 1967. It took 30 years later until the mid to late 1990s for a building boom of Canadian oil sands facilities to materialize. Source: Suncor Energy, Inc. internet website at www.suncor.com, under "our business," under "oil sands."

[20] Source: Alberta Employment, Immigration, and Industry, "Alberta Oil Sands Industry Update," December 2007, Table 1, pages 17 – 21.

and declined significantly, such that a number of these new projects were put on hold at that time.

Extensive oil shale resources exist in the United States both in eastern Appalachian black shales and western Green River Formation shales. Almost all of the domestic high-grade oil shale deposits with 25 gallons or more of petroleum per ton of rock are located in the Green River Formation, which is situated in Northwest Colorado (Piceance Basin), Northeast Utah (Uinta Basin), and Southwest Wyoming. It has been estimated that over 400 billion barrels of syncrude potential exists in Green River Formation deposits that would yield at least 30 gallons of syncrude per ton of rock in zones at least 100 feet thick.[21] Consequently, the Oil Shale Supply Submodule assumes that future oil shale syncrude production occurs exclusively in the Rocky Mountains within the 2035 time frame of the projections. Moreover, the immense size of the western oil shale resource base precluded the need for the submodule to explicitly track oil shale resource depletion through 2035.

For each projection year, the oil shale submodule calculates the net present cash flow of operating a commercial oil shale syncrude production facility, based on that future year's projected crude oil price. If the calculated discounted net present value of the cash flow exceeds zero, the submodule assumes that an oil shale syncrude facility would begin construction, so long as the construction of that facility is not precluded by the construction constraints specified by the market penetration algorithm. So the submodule contains two major decision points for determining whether an oil shale syncrude production facility is built in any particular year: first, whether the discounted net present value of a facility's cash flow exceeds zero; second, by a determination of the number of oil shale projects that can be initiated in that year, based on the maximum total oil shale production level that is permitted by the market penetration algorithm.

In any one year, many oil shale projects can be initiated, raising the projected production rates in multiples of the rate for the standard oil shale facility, which is assumed to be 50,000 barrels per day, per project.

Oil Shale Facility Cost and Operating Parameter Assumptions

The oil shale supply submodule is based on underground mining and surface retorting technology and costs. During the late 1970s and early 1980s, when petroleum companies were building oil shale demonstration plants, almost all demonstration facilities employed this technology.[22] The facility parameter values and cost estimates in the OSSS are based on information reported for the Paraho Oil Shale Project, and which are inflated to constant 2004 dollars.[23] Oil shale rock mining costs are based on Western United States underground coal mining costs, which would be representative of the cost of mining oil shale rock, [24] because coal

[21] Source: Culbertson, W. J. and Pitman, J. K. "Oil Shale" in *United States Mineral Resources*, USGS Professional Paper 820, Probst and Pratt, eds. P 497-503, 1973.

[22] Out of the many demonstration projects in the 1970s only Occidental Petroleum tested a modified in-situ approach which used caved-in mining areas to perform underground retorting of the kerogen.

[23] Source: Noyes Data Corporation, *Oil Shale Technical Data Handbook*, edited by Perry Nowacki, Park Ridge, New Jersey, 1981, pages 89-97.

[24] Based on the coal mining cost per ton data provided in coal company 2004 annual reports, particularly those of

mining techniques and technology would be employed to mine oil shale rock. However, the OSSS assumes that oil shale production costs fall at a rate of 1 percent per year, starting in 2005, to reflect the role of technological progress in reducing production costs. This cost reduction assumption results in oil shale production costs being 26 percent lower in 2035 relative to the initial 2004 cost structure.

Although the Paraho cost structure might seem unrealistic, given that the application of the in-situ process is more likely than the application of the underground mining/surface retorting process, the Paraho cost structure is well documented, while there is no detailed public information regarding the expected cost of the in-situ process. Even though the in-situ process might be cheaper per barrel of output than the Paraho process, this should be weighted against the following facts 1) oil and gas drilling costs have increased dramatically since 2005, somewhat narrowing that cost difference, and 2) the Paraho costs were determined at a time when environmental requirements were considerably less stringent. Consequently, the environmental costs that an energy production project would incur today are considerably more than what was envisioned in the late-1970s and early-1980s. It should also be noted that the Paraho process produces about the same volumes of oil and natural gas as the in-situ process does, and requires about the same electricity consumption as the in-situ process. Finally, to the degree that the Paraho process costs reported here are greater than the in-situ costs, the use of the Paraho cost structure provides a more conservative facility cost assessment, which is warranted for a completely new technology.

Another implicit assumption in the OSSS is that the natural gas produced by the facility is sold to other parties, transported offsite, and priced at prevailing regional wellhead natural gas prices. Similarly, the electricity consumed on site is purchased from the local power grid at prevailing industrial prices. Both the natural gas produced and the electricity consumed are valued in the Net Present Value calculations at their respective regional prices, which are determined elsewhere in the NEMS. Although the oil shale facility owner has the option to use the natural gas produced on-site to generate electricity for on-site consumption, building a separate on-site/offsite power generation decision process within OSSS would unduly complicate the OSSS logic structure and would not necessarily provide a more accurate portrayal of what might actually occur in the future.[25] Moreover, this treatment of natural gas and electricity prices automatically takes into consideration any embedded carbon dioxide emission costs associated with a particular NEMS scenario, because a carbon emissions allowance cost is embedded in the regional natural gas and electricity prices and costs.

OSSS Oil Shale Facility Configuration and Costs

The OSSS facility parameters and costs are based on those reported for the Paraho Oil Shale

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Arch Coal, Inc, CONSOL Energy Inc, and Massey Energy Company. Reported underground mining costs per ton range for $14.50 per ton to $27.50 per ton. The high cost figures largely reflect higher union wage rates, than the low cost figures reflect non-union wage rates. Because most of the Western underground mines are currently non-union, the cost used in OSSS was pegged to the lower end of the cost range. For example, the $14.50 per ton cost represents Arch Coal's average western underground mining cost.

[25] The Colorado/Utah/Wyoming region has relatively low electric power generation costs due to 1) the low cost of mining Powder River Basin subbituminous coal, and 2) the low cost of existing electricity generation equipment, which is inherently lower than new generation equipment due cost inflation and facility depreciation.

project. Because the Paraho Oil Shale Project costs were reported in 1976 dollars, the OSSS costs were inflated to constant 2004 dollar values. Similarly, the OSSS converts NEMS oil prices, natural gas prices, electricity costs, and carbon dioxide costs into constant 2004 dollars, so that all facility net present value calculations are done in constant 2004 dollars. Based on the Paraho Oil Shale Project configuration, OSSS oil shale facility parameters and costs are listed in Table 5-1, along the OSSS variable names. For the *Annual Energy Outlook 2009* and subsequent *Outlooks*, oil shale facility construction costs were increased by 50 percent to represent the world-wide increase in steel and other metal prices since the OSSS was initially designed. For the *Annual Energy Outlook 2011*, the oil shale facility plant size was reduced from 100,000 barrels per day to 50,000 barrels per day, based on discussions with industry representatives who believe that the smaller configuration was more likely for in-situ projects because this size captures most of the economies of scale, while also reducing project risk.

Table 5-1. OSSS Oil Shale Facility Configuration and Cost Parameters

Facility Parameters	OSSS Variable Name	Parameter Value
Facility project size	OS_PROJ_SIZE	50,000 barrels per day
Oil shale syncrude per ton of rock	OS_GAL_TON	30 gallons
Plant conversion efficiency	OS_CONV_EFF	90 percent
Average facility capacity factor	OS_CAP_FACTOR	90 percent per year
Facility lifetime	OS_PRJ_LIFE	20 years
Facility construction time	OS_PRJ_CONST	3 year
Surface facility capital costs	OS_PLANT_INVEST	$2.4 billion (2004 dollars)
Surface facility operating costs	OS_PLANT_OPER_CST	$200 million per year (2004 dollars)
Underground mining costs	OS_MINE_CST_TON	$17.50 per ton (2004 dollars)
Royalty rate	OS_ROYALTY_RATE	12.5 percent of syncrude value
Carbon Dioxide Emissions Rate	OS_CO2EMISS	150 metric tons per 50,000 bbl/day of production[26]

The construction lead time for oil shale facilities is assumed to be 3 years, which is less than the 5-year construction time estimates developed for the Paraho Project. The shorter construction period is based on the fact that the drilling of shallow in-situ heating and production wells can be accomplished much more quickly than the erection of a surface retorting facility. Because it is not clear when during the year a new plant will begin operation and achieve full productive capacity, OSSS assumes that production in the first full year will be at half its rated output and that full capacity will be achieved in the second year of operation.

To mimic the fact that an industry's costs decline over time due to technological progress, better management techniques, and so on, the OSSS initializes the oil shale facility costs in the year 2005 at the values shown above (i.e., surface facility construction and operating costs, and underground mining costs). After 2005, these costs are reduced by 1 percent per year through 2035, which is consistent with the rate of technological progress witnessed in the petroleum industry over the last few decades.

[26] Based on the average of the Fischer Assays determined for four oil shale rock samples of varying kerogen content. Op. cit. Noyes Data Corporation, Table 3.8, page 20.

OSSS Oil Shale Facility Electricity Consumption and Natural Gas Production Parameters

Based on the Paraho Oil Shale Project parameters, Table 5-2 provides the level of annual gas production and annual electricity consumption for a 50,000 barrel per day, operating at 100 percent capacity utilization for a full calendar year.[27]

Table 5-2. OSSS Oil Shale Facility Electricity Consumption and Natural Gas Production Parameters and Their Prices and Costs

Facility Parameters	OSSS Variable Name	Parameter Value
Natural gas production	OS_GAS_PROD	16.1 billion cubic feet per year
Wellhead gas sales price	OS_GAS_PRICE	Dollars per Mcf (2004 dollars)
Electricity consumption	OS_ELEC_CONSUMP	0.83 billion kilowatt-hours per year
Electricity consumption price	OS_ELEC_PRICE	Dollars per kilowatt-hour (2004 dollars)

Project Yearly Cash Flow Calculations

The OSSS first calculates the annual revenues minus expenditures, including income taxes and depreciation expenses, which is then discounted to a net present value. In those future years in which the net present value exceeds zero, a new oil shale facility can begin construction, subject to the timing constraints outlined below.

The discounted cash flow algorithm is calculated for a 23 year period, composed of 3 years for construction and 20 years for a plant's operating life. During the first 3 years of the 23-year period, only plant construction costs are considered with the facility investment cost being evenly apportioned across the 3 years. In the fourth year, the plant goes into partial operation, and produces 50 percent of the rated output. In the fifth year, revenues and operating expenses are assumed to ramp up to the full-production values, based on a 90 percent capacity factor that allows for potential production outages. During years 4 through 23, total revenues equal oil production revenues plus natural gas production revenues.[28]

Discounted cash flow oil and natural gas revenues are calculated based on prevailing oil and natural gas prices projected for that future year. In other words, the OSSS assumes that the economic analysis undertaken by potential project sponsors is solely based on the prevailing price of oil and natural gas at that time in the future and is not based either on historical price trends or future expected prices. Similarly, industrial electricity consumption costs are also based on the prevailing price of electricity for industrial consumers in that region at that future time.

As noted earlier, during a plant's first year of operation (year 4), both revenues and costs are half the values calculated for year 5 through year 23.

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[27] Op. cit. Noyes Data Corporation, pages 89-97.

[28] Natural gas production revenues result from the fact that significant volumes of natural gas are produced when the kerogen is retorted in the surface facilities. See prior table regarding the volume of natural gas produced for a 50,000 barrel per day oil shale syncrude facility.

Oil revenues are calculated for each year in the discounted cash flow as follows:

$$\begin{aligned} OIL\_REVENUE_t = {} & OIT\_WOP_t * (1.083/0.732) * OS\_PRJ\_SIZE \\ & * OS\_CAP\_FACTOR * 365 \end{aligned} \tag{5-8}$$

where

OIT_WOP_t	=	World oil price at time t in 1987 dollars
(1.083 / 0.732)	=	GDP chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_PROJ_PRJ_SIZE	=	Facility project size in barrels per day
OS_CAP_FACTOR	=	Facility capacity factor
365	=	Days per year.

Natural gas revenues are calculated for each year in the discounted cash flow as follows:

$$\begin{aligned} GAS\_REVENUE_t = {} & OS\_GAS\_PROD * OGPRCL48_t * 1.083/0.732) \\ & *OS\_CAP\_FACTOR, \end{aligned} \tag{5-9}$$

where

OS_GAS_PROD	=	Annual natural gas production for 50,000 barrel per day facility
$OGPRCL48_t$	=	Natural gas price in Rocky Mtn. at time t in 1987 dollars
(1.083 / 0.732)	=	GDP chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_CAP_FACTOR	=	Facility capacity factor.

Electricity consumption costs are calculated for each year in the discounted cash flow as follows:

$$\begin{aligned} ELECT\_COST_t = {} & OS\_ELEC\_CONSUMP * PELIN_t * (1.083/.732) * 0.003412 \\ & * OS\_CAP\_FACTOR \end{aligned} \tag{5-10}$$

where

OS_ELEC_CONSUMP	=	Annual electricity consumption for 50,000 barrel per day facility
$PELIN_t$	=	Electricity price Colorado/Utah/Wyoming at time t
(1.083 / .732)	=	GNP chain-type price deflators to convert 1987 dollars into 2004 dollars
OS_CAP_FACTOR	=	Facility capacity factor.

The carbon dioxide emission tax rate per metric ton is calculated as follows:

$$OS\_EMETAX_t = EMETAX_t(1) * 1000.0 * (12.0 / 44.0) * (1.083 / .732) \tag{5-11}$$

where,

$EMETAX_t(1)$	=	Carbon emissions allowance price/tax per kilogram at time t
1,000	=	Convert kilograms to metric tones
(12.0 / 44.0)	=	Atomic weight of carbon divided by atomic weight of carbon dioxide
(1.083 / .732)	=	GNP chain-type price deflators to convert 1987 dollars into 2004 dollars.

Annual carbon dioxide emission costs per plant are calculated as follows:

$$CO2\_COST_t = OS\_EMETAX_t * OS\_CO2EMISS * 365 * OS\_CAP\_FACTOR \tag{5-12}$$

where

OS_EMETAX_t	=	Carbon emissions allowance price/tax per metric tonne at time t in 2004 dollars
OS_CO2EMISS	=	Carbon dioxide emissions in metric tonnes per day
365	=	Days per year
OS_CAP_FACTOR	=	Facility capacity factor

In any given year, pre-tax project cash flow is:

$$PRETAX\_CASH\_FLOW_t = TOT\_REVENUE_t - TOTAL\_COST_t \tag{5-13}$$

where

$TOT\_REVENUE_t$	=	Total project revenues at time t
TOT_COST_t	=	Total project costs at time t.

Total project revenues are calculated as follows:

$$TOT\_REVENUE_t = OIL\_REVENUE_t + GAS\_REVENUE_t \tag{5-14}$$

Total project costs are calculated as follows:

$$\begin{aligned} TOT\_COST_t = & OS\_PLANT\_OPER\_CST + ROYALTY_t + PRJ\_MINE\_CST \\ & + ELEC\_COST_t + CO2\_COST_t + INVEST_t \end{aligned} \tag{5-15}$$

where

$OS\_PLANT\_OPER\_CST$	=	Annual plant operating costs per year
$ROYALTY_t$	=	Annual royalty costs at time t
PRJ_MINE_COST	=	Annual plant mining costs
$ELEC\_COST_t$	=	Annual electricity costs at time t
$CO2\_COST_t$	=	Annual carbon dioxide emissions costs at time t
$INVEST_t$	=	Annual surface facility investment costs.

While the plant is under construction (years 1 through 3) only INVEST has a positive value, while the other four cost elements equal zero. When the plant goes into operation (years 4 through 23), the capital costs (INVEST) are zero, while the other five operating costs take on positive values. The annual investment cost for the three years of construction is calculated as follows, under the assumption that the construction costs are evenly spread over the 3-year construction period:

$$INVEST = OS\_PLANT\_INVEST / OS\_PRJ\_CONST \tag{5-16}$$

where the variables are defined as in Table 5-1. Because the plant output is composed of both oil and natural gas, the annual royalty cost (ROYALTY) is calculated by applying the royalty rate to total revenues, as follows:

$$ROYALTY_t = OS\_ROYALTY\_RATE * TOT\_REVENUE_t \tag{5-17}$$

Annual project mining costs are calculated as the mining cost per barrel of syncrude multiplied by the number of barrels produced, as follows:

$$\begin{aligned} PRJ\_MINE\_COST = OS\_MINE\_CST\_TON * &\frac{42}{OS\_GALLON\_TON * OS\_CONV\_EFF} \\ &* OS\_PROJ\_SIZE * OS\_CAP\_FACTOR * 365 \end{aligned} \tag{5-18}$$

where

42	=	gallons per barrel
365	=	days per year.

After the plant goes into operation and after a pre-tax cash flow is calculated, then a post-tax cash flow has to be calculated based on income taxes and depreciation tax credits. When the prevailing world oil price is sufficiently high and the pre-tax cash flow is positive, then the following post-tax cash flow is calculated as

$$\begin{aligned} CASH\_FLOW_t = &\left(PRETAX\_CASH\_FLOW_t * (1 - OS\_CORP\_TAX\_RATE)\right) + \\ &(OS\_CORP\_TAX\_RATE * OS\_PLANT\_INVEST / OS\_PRJ\_LIFE) \end{aligned} \tag{5-19}$$

The above depreciation tax credit calculation assumes straight-line depreciation over the operating life of the investment (OS_PRJ_LIFE).

Discount Rate Financial Parameters

The discounted cash flow algorithm uses the following financial parameters to determine the discount rate used in calculating the net present value of the discounted cash flow.

Table 5-3. Discount Rate Financial Parameters

Financial Parameters	OSSS Variable Name	Parameter Value
Corporate income tax rate	OS_CORP_TAX_RATE	38 percent
Equity share of total facility capital	OS_EQUITY_SHARE	60 percent
Facility equity beta	OS_EQUITY_VOL	1.8
Expected market risk premium	OS_EQUITY_PREMIUM	6.5 percent
Facility debt risk premium	OS_DEBT_PREMIUM	0.5 percent

The corporate equity beta (OS_EQUITY_VOL) is the project risk beta, not a firm's volatility of stock returns relative to the stock market's volatility. Because of the technology and construction uncertainties associated with oil shale plants, the project's equity holder's risk is expected to be somewhat greater than the average industry firm beta. The median beta for oil and gas field exploration service firms is about 1.65. Because a project's equity holders' investment risk level is higher, the facility equity beta assumed for oil shale projects is 1.8.

The expected market risk premium (OS_EQUITY_PREMIUM), which is 6.5 percent, is the expected return on market (S&P 500) over the rate of 10-year Treasury note (risk-free rate). A Monte Carlo simulation methodology was used to estimate the expected market return.

Oil shale project bond ratings are expected to be in the Ba-rating range. Since the NEMS macroeconomic module endogenously determines the industrial Baa bond rates for the forecasting period, the cost of debt rates are different in each year. The debt premium (OS_DEBT_PREMIUM) adjusts the bond rating for the project from the Baa to the Ba range, which is assumed to be constant at the average historical differential over the forecasting period.

Discount Rate Calculation

A seminal parameter used in the calculation of the net present value of the cash flow is the discount rate. The calculation of the discount rate used in the oil shale submodule is consistent with the way the discount rate is calculated through the National Energy Modeling System. The discount rate equals the post-tax weighted average cost of capital, which is calculated in the OSSS as follows:

$$\begin{aligned}OS\_DISCOUNT\_RATE_t = (((1-OS\_EQUITY\_SHARE)*(MC\_RMCORPBAA_t/100+ \\ OS\_DEBT\_PREMIUM))*(1-OS\_CORP\_TAX\_RATE)+ \\ (OS\_EQUITY\_SHARE*((OS\_EQUITY\_PREMIUM* \\ OS\_EQUITY\_VOL)+MC\_RMGFCM\_10NS_t/100))\end{aligned} \quad (5\text{-}20)$$

where

OS_EQUITY_SHARE	=	Equity share of total facility capital
$MC\_RMCORPBAA_t/100$	=	BAA corporate bond rate
OS_DEBT_PREMIUM	=	Facility debt risk premium
OS_CORP_TAX_RATE	=	Corporate income tax rate
OS_EQUITY_PREMIUM	=	Expected market risk premium
OS_EQUITY_VOL	=	Facility equity volatility beta
$MC\_RMGFCM\_10NS_t/100$	=	10-year Treasury note rate.

In calculating the facility's cost of equity, the equity risk premium (which is a product of the expected market premium and the facility equity beta, is added to a "risk-free" rate of return, which is considered to be the 10-year Treasury note rate.

The nominal discount rate is translated into a constant, real discount rate using the following formula:

$$OS\_DISCOUNT\_RATE_t = ((1.0+OS\_DISCOUNT\_RATE_t)/(1.0+INFL_t))-1.0 \quad (5\text{-}21)$$

where

$INFL_t$ = Inflation rate at time t.

Net Present Value Discounted Cash Flow Calculation

So far a potential project's yearly cash flows have been calculated along with the appropriate discount rate. Using these calculated quantities, the net present value of the yearly cash flow values is calculated as follows:

$$NET\_CASH\_FLOW_{t-1} = \sum_{t=1}^{OS\_PRJ\_LIFE+OS\_PRJ\_CONST}\left[CASH\_FLOW_t * \left[\frac{1}{1+OS\_DISCOUNT\_RATE_t}\right]^t\right] \quad (5\text{-}22)$$

If the net present value of the projected cash flows exceeds zero, then the potential oil shale facility is considered to be economic and begins construction, so long as this facility construction does not violate the construction timing constraints detailed below.

Oil Shale Facility Market Penetration Algorithm

As noted in the introduction, there is no empirical basis for determining how rapidly new oil shale facilities would be built, once the OSSS determines that surface-retorting oil shale facilities are economically viable, because no full-scale commercial facilities have ever been constructed. However, there are three primary constraints to oil shale facility construction. First, the construction of an oil shale facility cannot be undertaken until the in-situ technology has been sufficiently developed and tested to be deemed ready for its application to commercial size projects (i.e., 50,000 barrels per day). Second, oil shale facility construction is constrained by the maximum oil shale production limit. Third, oil shale production volumes cannot reach the maximum oil shale production limit any earlier than 40 years after the in-situ technology has been deemed to be feasible and available for commercial size facilities. Table 5-4 summarizes the primary market penetration parameters in the OSSS.

Table 5-4. Market Penetration Parameters

Market Penetration Parameters	OSSS Variable Name	Parameter Value
Earliest Facility Construction Start Date	OS_START_YR	2017
Maximum Oil Shale Production	OS_MAX_PROD	2 million barrels per year
Minimum Years to Reach Full Market Penetration	OS_PENETRATE_YR	40

Shell's in-situ oil shale RD&D program is considered to be the most advanced, having begun in 1997. Shell is most likely to be the first party to build and operate a commercial scale oil shale production facility. Based on conversations between Shell personnel and EIA personnel, Shell is likely to conclude its field experiments, which test the various components of a commercial facility sometime during the 2014 through 2017 timeframe. Consequently, the earliest likely initiation of a full-scale commercial plant would be 2017.[29]

As discussed earlier, a 2 million barrel per day oil shale production level at the end of 40-year market penetration period is considered to be reasonable and feasible based on the size of the resource base and the volume and availability of water needed to develop those resources. The actual rate of market penetration in the OSSS, however, is ultimately determined by the projected profitability of oil shale projects. At a minimum, oil and natural gas prices must be sufficiently high to produce a facility revenue stream (i.e., discounted cash flow) that covers all capital and operating costs, including the weighted average cost of capital. When the discounted cash flow exceeds zero (0), then the market penetration algorithm allows oil shale facility construction to commence.

[29] Op. cit. EIA/OIAF/OGD memorandum entitled, "Oil Shale Project Size and Production Ramp-Up," and based on public information and private conversations subsequent to the development of that memorandum.

When project discounted cash flow is greater than zero, the relative project profitability is calculated as follows:

$$OS\_PROFIT_t = DCF_t \ / \ OS\_PLANT\_INVEST \qquad (5\text{-}23)$$

where

DCF_t = Project discounted cash flow at time t
OS_PLANT_INVEST = Project capital investment

OS_PROFIT is an index of an oil project's expected profitability. The expectation is that, as OS_PROFIT increases, the relative financial attractiveness of producing oil shale also increases.

The level of oil shale facility construction that is permitted in any year depends on the maximum oil shale production that is permitted by the following market penetration algorithm:

$$\begin{aligned} MAX\_PROD_t &= OS\_MAX\_PROD * (OS\_PROFIT_t \ / \ (1 + OS\_PROFIT_t)) \\ &\quad * ((T - (OS\_START\_YR - 1989)) \ / \ OS\_PENETRATE\_YR) \end{aligned} \qquad (5\text{-}24)$$

where,

OS_MAX_PROD	=	Maximum oil shale production limit
OS_PROFIT_t	=	Relative oil shale project profitability at time t
T	=	Time t
OS_START_YR	=	First year that an oil shale facility can be built
OS_PENTRATE_YR	=	Minimum number of years during which the maximum oil shale production can be achieved.

The OS_PROFIT portion of the market penetration algorithm (5-24) rapidly increases market penetration as the DCF numerator of OS_PROFIT increases. However, as OS_PROFIT continues to increase, the rate of increase in market penetration slows as (OS_PROFIT / (1 + OS_PROFIT) asymptotically approaches one (1.0). As this term approaches 1.0, the algorithm's ability to build more oil shale plants is ultimately constrained by OS_MAX_PROD term, regardless of how financially attractive the construction of new oil shale facilities might be. This formulation also prevents MAX_PROD from exceeding OS_MAX_PROD.

The second portion of the market penetration algorithm specifies that market penetration increases linearly over the number of years specified by OS_PENETRATE_YR. As noted earlier OS_PENETRATE_YR specifies the minimum number of years over which the oil shale industry can achieve maximum penetration. The maximum number of years required to achieve full penetration is dictated by the speed at which the OS_PROFIT portion of the equation approaches one (1.0). If OS_PROFIT remains low, then it is possible that MAX_PROD never comes close to reaching the OS_MAX_PROD value.

The number of new oil shale facilities that start construction in any particular year is specified by the following equation:

(5-25)

$$\text{OS\_PLANTS\_NEW}_t = \text{INT}((\text{MAX\_PROD}_t - (\text{OS\_PLANTS}_t * \text{OS\_PRJ\_SIZE} * \text{OS\_CAP\_FACTOR})) / (\text{OS\_PRJ\_SIZE} * \text{OS\_CAP\_FACTOR}))$$

where

MAX_PROD_t	=	Maximum oil shale production at time t
OS_PLANT_t	=	Number of existing oil shale plants at time t
OS_PRJ_SIZE	=	Standard oil shale plant size in barrels per day
OS_CAP_FACTOR	=	Annual capacity factor of an oil shale plant in percent per year.

The first portion of the above formula specifies the incremental production capacity that can be built in any year, based on the number of plants already in existence. The latter portion of the equation determines the integer number of new plants that can be initiated in that year, based on the expected annual production rate of an oil shale plant.

Because oil shale production is highly uncertain, not only from a technological and economic perspective, but also from an environmental perspective, an upper limit to oil shale production is assumed within the OSSS. The upper limit on oil shale production is 2 million barrels per day, which is equivalent to 44 facilities of 50,000 barrels per day operating at a 90 percent capacity factor. So the algorithm allows enough plants to be built to fully reach the oil shale production limit, based on the expected plant capacity factor. As noted earlier, the oil shale market penetration algorithm is also limited by the earliest commercial plant construction date, which is assumed to be no earlier than 2017.

While the OSSS costs and performance profiles are based on technologies evaluated in the 1970's and early 1980's, the complete absence of any current commercial-scale oil shale production makes its future economic development highly uncertain. If the technological, environmental, and economic hurdles are as high or higher than those experienced during the 1970's, then the prospects for oil shale development would remain weak throughout the projections. However, technological progress can alter the economic and environmental landscape in unanticipated ways. For example, if an in-situ oil shale process were to be demonstrated to be both technically feasible and commercially profitable, then the prospects for an oil shale industry would improve significantly, and add vast economically recoverable oil resources in the United States and possibly elsewhere in the world.

Appendix A. Discounted Cash Flow Algorithm

Introduction

The basic DCF methodology used in the Oil and Gas Supply Module (OGSM) is applied for a broad range of oil or natural gas projects, including single well projects or multiple well projects within a field. It is designed to capture the effects of multi-year capital investments (e.g., offshore platforms). The expected discounted cash flow value associated with exploration and/or development of a project with oil or gas as the primary fuel in a given region evaluated in year T may be presented in a stylized form (Equation A-1).

$$\begin{aligned} DCF_T = (&PVTREV - PVROY - PVPRODTAX - PVDRILLCOST - PVEQUIP \\ &- PVKAP - PVOPCOST - PVABANDON - PVSIT - PVFIT)_T \end{aligned} \tag{A-1}$$

where

T	=	year of evaluation
PVTREV	=	present value of expected total revenues
PVROY	=	present value of expected royalty payments
PVPRODTAX	=	present value of expected production taxes (ad valorem and severance taxes)
PVDRILLCOST	=	present value of expected exploratory and developmental drilling expenditures
PVEQUIP	=	present value of expected lease equipment costs
PVKAP	=	present value of other expected capital costs (i.e., gravel pads and offshore platforms)
PVOPCOST	=	present value of expected operating costs
PVABANDON	=	present value of expected abandonment costs
PVSIT	=	present value of expected state corporate income taxes
PVFIT	=	present value of expected federal corporate income taxes.

Costs are assumed constant over the investment life but vary across both region and primary fuel type. This assumption can be changed readily if required by the user. Relevant tax provisions also are assumed unchanged over the life of the investment. Operating losses incurred in the initial investment period are carried forward and used against revenues generated by the project in later years.

The following sections describe each component of the DCF calculation. Each variable of Equation A.1 is discussed starting with the expected revenue and royalty payments, followed by the expected costs, and lastly the expected tax payments.

Present Value of Expected Revenues, Royalty Payments, and Production Taxes

Revenues from an oil or gas project are generated from the production and sale of both the primary fuel as well as any co-products. The present value of expected revenues measured at the wellhead from the production of a representative project is defined as the summation of yearly expected net wellhead price[1]

[1]The DCF methodology accommodates price expectations that are myopic, adaptive, or perfect. The default is myopic expectations, so prices are assumed to be constant throughout the economic evaluation period.

times expected production[2] discounted at an assumed rate. The discount rate used to evaluate private investment projects typically represents a weighted average cost of capital (WACC), i.e., a weighted average of both the cost of debt and the cost of equity.

Fundamentally, the formula for the WACC is straightforward.

$$WACC = \frac{D}{D+E} * R_D * (1-t) + \frac{E}{D+E} * R_E \tag{A-2}$$

where D = market value of debt, E = market value of equity, t = corporate tax rate, R_D = cost of debt, and R_E = cost of equity. Because the drilling projects being evaluated are long term in nature, the values for all variables in the WACC formula are long run averages.

The WACC calculated using the formula given above is a nominal one. The real value can be calculated by

$$disc = \frac{(1+WACC)}{(1+\pi_e)} - 1 \tag{A-3}$$

where π_e = expected inflation rate. The expected rate of inflation over the forecasting period is measured as the average annual rate of change in the U.S. GDP deflator over the forecasting period using the forecasts of the GDP deflator from the Macro Module (MC_JPGDP).

The present value of expected revenue for either the primary fuel or its co-product is calculated as follows:

$$PVREV_{T,k} = \sum_{t=T}^{T+n} \left[Q_{t,k} * \lambda * P_{t,k} * \left[\frac{1}{1+disc} \right]^{t-T} \right], \lambda = \begin{cases} 1 \text{ if primary fuel} \\ COPRD \text{ if secondary fuel} \end{cases} \tag{A-4}$$

where,

k	=	fuel type (oil or natural gas)
T	=	time period
n	=	number of years in the evaluation period
disc	=	discount rate
Q	=	expected production volumes
P	=	expected net wellhead price
COPRD	=	co-product factor.[3]

Net wellhead price is equal to the market price minus any transportation costs. Market prices for oil and gas are defined as follows: the price at the receiving refinery for oil, the first purchase price for onshore natural gas, the price at the coastline for offshore natural gas, and the price at the Canadian border for Alaskan gas.

[2]Expected production is determined outside the DCF subroutine. The determination of expected production is described in Chapter 3.

[3]The OGSM determines coproduct production as proportional to the primary product production. COPRD is the ratio of units of coproduct per unit of primary product.

The present value of the total expected revenue generated from the representative project is

$$PVTREV_T = PVREV_{T,1} + PVREV_{T,2} \tag{A-5}$$

where

$PVREV_{T,1}$ = present value of expected revenues generated from the primary fuel
$PVREV_{T,2}$ = present value of expected revenues generated from the secondary fuel.

Present Value of Expected Royalty Payments

The present value of expected royalty payments (PVROY) is simply a percentage of expected revenue and is equal to

$$PVROY_T = ROYRT_1 * PVREV_{T,1} + ROYRT_2 * PVREV_{T,2} \tag{A-6}$$

where

ROYRT = royalty rate, expressed as a fraction of gross revenues.

Present Value of Expected Production Taxes

Production taxes consist of ad valorem and severance taxes. The present value of expected production tax is given by

$$\begin{aligned} PVPRODTAX_T = {} & PRREV_{T,1} * (1 - ROYRT_1) * PRDTAX_1 + PVREV_{T,2} \\ & *(1 - ROYRT_2) * PRODTAX_2 \end{aligned} \tag{A-7}$$

where

PRODTAX = production tax rate.

PVPRODTAX is computed as net of royalty payments because the investment analysis is conducted from the point of view of the operating firm in the field. Net production tax payments represent the burden on the firm because the owner of the mineral rights generally is liable for his/her share of these taxes.

Present Value of Expected Costs

Costs are classified within the OGSM as drilling costs, lease equipment costs, other capital costs, operating costs (including production facilities and general/administrative costs), and abandonment costs. These costs differ among successful exploratory wells, successful developmental wells, and dry holes. The present value calculations of the expected costs are computed in a similar manner as PVREV (i.e., costs are discounted at an assumed rate and then summed across the evaluation period).

Present Value of Expected Drilling Costs

Drilling costs represent the expenditures for drilling successful wells or dry holes and for equipping successful wells through the Christmas tree installation.[4] Elements included in drilling costs are labor,

[4]The Christmas tree refers to the valves and fittings assembled at the top of a well to control the fluid flow.

material, supplies and direct overhead for site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling, running and cementing casing, machinery, tool changes, and rentals. The present value of expected drilling costs is given by

$$\begin{aligned}PVDRILLCOST_T = \sum_{t=T}^{T+n} \Bigg[\Big[& COSTEXP_T * SR_1 * NUMEXP_t + COSTDEV_T * SR_2 * NUMDEV_t \\ & + COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t \\ & + COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \Big] * \left(\frac{1}{1 + disc}\right)^{t-T} \Bigg]\end{aligned} \quad \text{(A-8)}$$

where

COSTEXP	=	drilling cost for a successful exploratory well
SR	=	success rate (1=exploratory, 2=developmental)
COSTDEV	=	drilling cost for a successful developmental well
COSTDRY	=	drilling cost for a dry hole (1=exploratory, 2=developmental).
NUMEXP	=	number of exploratory wells drilled in a given period
NUMDEV	=	number of developmental wells drilled in a given period.

The number and schedule of wells drilled for an oil or gas project are supplied as part of the assumed production profile. This is based on historical drilling activities.

Present Value of Expected Lease Equipment Costs

Lease equipment costs include the cost of all equipment extending beyond the Christmas tree, directly used to obtain production from a drilled lease. Three categories of costs are included: producing equipment, the gathering system, and processing equipment. Producing equipment costs include tubing, rods, and pumping equipment. Gathering system costs consist of flowlines and manifolds. Processing equipment costs account for the facilities utilized by successful wells.

The present value of expected lease equipment cost is

$$PVEQUIP_T = \sum_{t=T}^{T+n} \left[EQUIP_t * (SR_1 * NUMEXP_t + SR_2 * NUMDEV_t) * \left[\frac{1}{1 + disc}\right]^{t-T} \right] \quad \text{(A-9)}$$

where

EQUIP	=	lease equipment costs per well.

Present Value of Other Expected Capital Costs

Other major capital expenditures include the cost of gravel pads in Alaska, and offshore platforms. These costs are exclusive of lease equipment costs. The present value of other expected capital costs is calculated as

$$PVKAP_T = \sum_{t=T}^{T+n} \left[KAP_t * \left[\frac{1}{1 + disc}\right]^{t-T} \right] \quad \text{(A-10)}$$

where

KAP = other major capital expenditures, exclusive of lease equipment.

Present Value of Expected Operating Costs

Operating costs include three main categories of costs: normal daily operations, surface maintenance, and subsurface maintenance. Normal daily operations are further broken down into supervision and overhead, labor, chemicals, fuel, water, and supplies. Surface maintenance accounts for all labor and materials necessary to keep the service equipment functioning efficiently and safely. Costs of stationary facilities, such as roads, also are included. Subsurface maintenance refers to the repair and services required to keep the downhole equipment functioning efficiently.

Total operating cost in time t is calculated by multiplying the cost of operating a well by the number of producing wells in time t. Therefore, the present value of expected operating costs is as follows:

$$PVOPCOST_T = \sum_{t=T}^{T+n} \left[OPCOST_t * \sum_{k=1}^{t} \left[SR_1 * NUMEXP_k + SR_2 * NUMDEV_k \right] * \left(\frac{1}{1+disc} \right)^{t-T} \right] \quad (A\text{-}11)$$

where

OPCOST = operating costs per well.

Present Value of Expected Abandonment Costs

Producing facilities are eventually abandoned and the cost associated with equipment removal and site restoration is defined as

$$PVABANDON_T = \sum_{t=T}^{T+n} \left[COSTABN_t * \left[\frac{1}{1+disc} \right]^{t-T} \right] \quad (A\text{-}12)$$

where

COSTABN = abandonment costs.

Drilling costs, lease equipment costs, operating costs, abandonment costs, and other capital costs incurred in each individual year of the evaluation period are integral components of the following determination of State and Federal corporate income tax liability.

Present Value of Expected Income Taxes

An important aspect of the DCF calculation concerns the tax treatment. All expenditures are divided into depletable,[5] depreciable, or expensed costs according to current tax laws. All dry hole and operating costs are expensed. Lease costs (i.e., lease acquisition and geological and geophysical costs) are capitalized and then amortized at the same rate at which the reserves are extracted (cost depletion). Drilling costs are split between tangible costs (depreciable) and intangible drilling costs (IDC's) (expensed). IDC's include

[5]The DCF methodology does not include lease acquisition or geological & geophysical expenditures because they are not relevant to the incremental drilling decision.

wages, fuel, transportation, supplies, site preparation, development, and repairs. Depreciable costs are amortized in accord with schedules established under the Modified Accelerated Cost Recovery System (MACRS).

Key changes in the tax provisions under the tax legislation of 1988 include the following:

! Windfall Profits Tax on oil was repealed,

! Investment Tax Credits were eliminated, and

! Depreciation schedules shifted to a Modified Accelerated Cost Recovery System.

Tax provisions vary with type of producer (major, large independent, or small independent) as shown in Table A-1. A major oil company is one that has integrated operations from exploration and development through refining or distribution to end users. An independent is any oil and gas producer or owner of an interest in oil and gas property not involved in integrated operations. Small independent producers are those with less than 1,000 barrels per day of production (oil and gas equivalent). The present DCF methodology reflects the tax treatment provided by current tax laws for large independent producers.

The resulting present value of expected taxable income (PVTAXBASE) is given by:

$$\mathrm{PVTAXBASE}_T = \sum_{t=T}^{T+n} \Big[\big(\mathrm{TREV}_t - \mathrm{ROY}_t - \mathrm{PRODTAX}_t - \mathrm{OPCOST}_t - \mathrm{ABANDON}_t - \mathrm{XIDC}_t - \mathrm{AIDC}_t - \mathrm{DEPREC}_t - \mathrm{DHC}_t\big) * \left(\frac{1}{1+\mathrm{disc}}\right)^{t-T} \Big] \quad \text{(A-13)}$$

where

T	=	year of evaluation
t	=	time period
n	=	number of years in the evaluation period
TREV	=	expected revenues
ROY	=	expected royalty payments
PRODTAX	=	expected production tax payments
OPCOST	=	expected operating costs
ABANDON	=	expected abandonment costs
XIDC	=	expected expensed intangible drilling costs
AIDC	=	expected amortized intangible drilling costs[6]
DEPREC	=	expected depreciable tangible drilling, lease equipment costs, and other capital expenditures
DHC	=	expected dry hole costs
disc	=	expected discount rate.

TREV_t, ROY_t, $\mathrm{PRODTAX}_t$, OPCOST_t, and $\mathrm{ABANDON}_t$ are the undiscounted individual year values. The following sections describe the treatment of expensed and amortized costs for the purpose of determining corporate income tax liability at the State and Federal level.

[6]This variable is included only for completeness. For large independent producers, all intangible drilling costs are expensed.

Expected Expensed Costs

Expensed costs are intangible drilling costs, dry hole costs, operating costs, and abandonment costs. Expensed costs and taxes (including royalties) are deductible from taxable income.

Expected Intangible Drilling Costs

For large independent producers, all intangible drilling costs are expensed. However, this is not true across the producer category (as shown in Table A-1). In order to maintain analytic flexibility with respect to changes in tax provisions, the variable XDCKAP (representing the portion of intangible drilling costs that must be depreciated) is included.

Table A-1. Tax Treatment in Oil and Gas Production by Category of Company Under Current Tax Legislation

Costs by Tax Treatment	Majors	Large Independents	Small Independents
Depletable Costs	**Cost Depletion** G&G[a] Lease Acquisition	**Cost Depletion**[b] G&G Lease Acquisition	**Maximum of Percentage or Cost Depletion** G&G Lease Acquisition
Depreciable Costs	**MACRS**[c] Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s **5-year SLM**[d] 20 percent of IDC=s	**MACRS** Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s	**MACRS** Lease Acquisition Other Capital Expenditures Successful Well Drilling Costs Other than IDC=s
Expensed Costs	Dry Hole Costs 80 percent of IDC's Operating Costs	Dry Hole Costs 80 percent of IDC's Operating Costs	Dry Hole Costs 80 percent of IDC's Operating Costs

[a]Geological and geophysical.
[b]Applicable to marginal project evaluation; first 1,000 barrels per day depletable under percentage depletion.
[c]Modified Accelerated Cost Recovery System; the period of recovery for depreciable costs will vary depending on the type of depreciable asset.
[d]Straight Line Method.

Expected expensed IDC's are defined as follows:

$$\begin{aligned} XIDC_t = {} & COSTEXP_T * (1 - EXKAP) * (1 - XDCKAP) * SR_1 * NUMEXP_t \\ & + COSTDEV_T * (1 - DVKAP) * (1 - XDCKAP) * SR_2 * NUMDEV_t \end{aligned} \tag{A-14}$$

where

COSTEXP	=	drilling cost for a successful exploratory well
EXKAP	=	fraction of exploratory drilling costs that are tangible and must be depreciated
XDCKAP	=	fraction of intangible drilling costs that must be depreciated[7]
SR	=	success rate (1=exploratory, 2=developmental)
NUMEXP	=	number of exploratory wells
COSTDEV	=	drilling cost for a successful developmental well
DVKAP	=	fraction of developmental drilling costs that are tangible and must be depreciated
NUMDEV	=	number of developmental wells.

If only a portion of IDC's are expensed (as is the case for major producers), the remaining IDC's must be depreciated. The model assumes that these costs are recovered at a rate of 10 percent in the first year, 20 percent annually for four years, and 10 percent in the sixth year; this method of estimating the costs is referred to as the 5-year Straight Line Method (SLM) with half-year convention. If depreciable costs accrue when fewer than 6 years remain in the life of the project, the recovered costs are estimated using a simple straight line method over the remaining period.

Thus, the value of expected depreciable IDC's is represented by

$$\begin{aligned} AIDC_t = \sum_{j=\beta}^{t} \Big[& \big(COSTEXP_T * (1 - EXKAP) * XDCKAP * SR_1 * NUMEXP_j \\ & + COSTDEV_T * (1 - DVKAP) * XDCKAP * SR_2 * NUMDEV_j\big) \\ & * DEPIDC_t * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j} \Big], \end{aligned} \tag{A-15}$$

$$\beta = \begin{cases} T \ \text{ for } t \le T + m - 1 \\ t - m + 1 \text{ for } \ t > T + m - 1 \end{cases}$$

where,

j	=	year of recovery
β	=	index for write-off schedule
DEPIDC	=	for t # n+T-m, 5-year SLM recovery schedule with half year convention; otherwise, 1/(n+T-t) in each period
infl	=	expected inflation rate[8]
disc	=	expected discount rate
m	=	number of years in standard recovery period.

AIDC will equal zero by default since the DCF methodology reflects the tax treatment pertaining to large independent producers.

[7]The fraction of intangible drilling costs that must be depreciated is set to zero as a default to conform with the tax perspective of a large independent firm.

[8]The write-off schedule for the 5-year SLM give recovered amounts in nominal dollars. Therefore, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars since the DCF calculation is based on constant dollar values for all other variables.

Expected Dry Hole Costs

All dry hole costs are expensed. Expected dry hole costs are defined as

$$DHC_t = COSTDRY_{T,1} * (1 - SR_1) * NUMEXP_t + COSTDRY_{T,2} * (1 - SR_2) * NUMDEV_t \qquad \text{(A-16)}$$

where

COSTDRY = drilling cost for a dry hole (1=exploratory, 2=developmental).

Total expensed costs in any year equals the sum of $XIDC_t$, $OPCOST_t$, $ABANDON_t$, and DHC_t.

Expected Depreciable Tangible Drilling Costs, Lease Equipment Costs and Other Capital Expenditures

Amortization of depreciable costs, excluding capitalized IDC's, conforms to the Modified Accelerated

Table A-2. MACRS Schedules
(Percent)

Year	3-year Recovery Period	5-year Recovery Period	7-year Recovery Period	10-year Recovery Period	15-year Recovery Period	20-year Recovery Period
1	33.33	20.00	14.29	10.00	5.00	3.750
2	44.45	32.00	24.49	18.00	9.50	7.219
3	14.81	19.20	17.49	14.40	8.55	6.677
4	7.41	11.52	12.49	11.52	7.70	6.177
5		11.52	8.93	9.22	6.93	5.713
6		5.76	8.92	7.37	6.23	5.285
7			8.93	6.55	5.90	4.888
8			4.46	6.55	5.90	4.522
9				6.56	5.91	4.462
10				6.55	5.90	4.461
11				3.28	5.91	4.462
12					5.90	4.461
13					5.91	4.462
14					5.90	4.461
15					5.91	4.462
16					2.95	4.461
17						4.462
18						4.461
19						4.462
20						4.461
21						2.231

Source: U.S. Master Tax Guide.

Cost Recovery System (MACRS) schedules. The schedules under differing recovery periods appear in Table A-2. The particular period of recovery for depreciable costs will conform to the specifications of the tax code. These recovery schedules are based on the declining balance method with half year convention. If depreciable costs accrue when fewer years remain in the life of the project than would allow for cost recovery over the standard period, then costs are recovered using a straight line method over the remaining period.

The expected tangible drilling costs, lease equipment costs, and other capital expenditures is defined as

$$\begin{aligned}
DEPREC_t = \sum_{j=\beta}^{t} \Big[\big[& (COSTEXP_T * EXKAP + EQUIP_T) * SR_1 * NUMEXP_j \\
& + (COSTDEV_T * DVKAP + EQUIP_T) * SR_2 * NUMDEV_j + KAP_j \big] \\
& * DEP_{t-j+1} * \left(\frac{1}{1+infl}\right)^{t-j} * \left(\frac{1}{1+disc}\right)^{t-j} \Big],
\end{aligned} \tag{A-17}$$

$$\beta = \begin{cases} T \ \text{ for } t \le T + m - 1 \\ t - m + 1 \ \text{ for } \ t > T + m - 1 \end{cases}$$

where

j	=	year of recovery
β	=	index for write-off schedule
m	=	number of years in standard recovery period
COSTEXP	=	drilling cost for a successful exploratory well
EXKAP	=	fraction of exploratory drilling costs that are tangible and must be depreciated
EQUIP	=	lease equipment costs per well
SR	=	success rate (1=exploratory, 2=developmental)
NUMEXP	=	number of exploratory wells
COSTDEV	=	drilling cost for a successful developmental well
DVKAP	=	fraction of developmental drilling costs that are tangible and must be depreciated
NUMDEV	=	number of developmental wells drilled in a given period
KAP	=	major capital expenditures such as gravel pads in Alaska or offshore platforms, exclusive of lease equipment
DEP	=	for t # n+T-m, MACRS with half year convention; otherwise, 1/(n+T-t) in each period
infl	=	expected inflation rate[9]
disc	=	expected discount rate.

Present Value of Expected State and Federal Income Taxes

The present value of expected state corporate income tax is determined by

$$PVSIT_T = PVTAXBASE_T * STRT \tag{A-18}$$

where

PVTAXBASE	=	present value of expected taxable income (Equation A.14)
STRT	=	state income tax rate.

[9]Each of the write-off schedules give recovered amounts in nominal dollars. Therefore, recovered costs are adjusted for expected inflation to give an amount in expected constant dollars since the DCF calculation is based on constant dollar values for all other variables.

The present value of expected federal corporate income tax is calculated using the following equation:

$$PVFIT_T = PVTAXBASE_T * (1 - STRT) * FDRT \tag{A-19}$$

where

FDRT = federal corporate income tax rate.

Summary

The discounted cash flow calculation is a useful tool for evaluating the expected profit or loss from an oil or gas project. The calculation reflects the time value of money and provides a good basis for assessing and comparing projects with different degrees of profitability. The timing of a project's cash inflows and outflows has a direct affect on the profitability of the project. As a result, close attention has been given to the tax provisions as they apply to costs.

The discounted cash flow is used in each submodule of the OGSM to determine the economic viability of oil and gas projects. Various types of oil and gas projects are evaluated using the proposed DCF calculation, including single well projects and multi-year investment projects. Revenues generated from the production and sale of co-products also are taken into account.

The DCF routine requires important assumptions, such as assumed costs and tax provisions. Drilling costs, lease equipment costs, operating costs, and other capital costs are integral components of the discounted cash flow analysis. The default tax provisions applied to the costs follow those used by independent producers. Also, the decision to invest does not reflect a firm's comprehensive tax plan that achieves aggregate tax benefits that would not accrue to the particular project under consideration.

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Appendix C. Model Abstract

1. Model Name
   Oil and Gas Supply Module

2. Acronym
   OGSM

3. Description
   OGSM projects the following aspects of the crude oil and natural gas supply industry:
   - production
   - reserves
   - drilling activity
   - natural gas imports and exports

4. Purpose
   OGSM is used by the Oil and Gas Division in the Office of Integrated Analysis and Forecasting as an analytic aid to support preparation of projections of reserves and production of crude oil and natural gas at the regional and national level. The annual projections and associated analyses appear in the *Annual Energy Outlook* (DOE/EIA-0383) of the U.S. Energy Information Administration. The projections also are provided as a service to other branches of the U.S. Department of Energy, the Federal Government, and non-Federal public and private institutions concerned with the crude oil and natural gas industry.

5. Date of Last Update
   2010

6. Part of Another Model
   National Energy Modeling System (NEMS)

7. Model Interface References
   Coal Module
   Electricity Module
   Industrial Module
   International Module
   Natural Gas Transportation and Distribution Model (NGTDM)
   Macroeconomic Module
   Petroleum Market Module (PMM)

8. Official Model Representative
   Office: Integrating Analysis and Forecasting
   Division: Oil and Gas Analysis
   Model Contact: Dana Van Wagener
   Telephone: (202) 586-4725

9. Documentation Reference
   U.S. Department of Energy. 2009. *Documentation of the Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063, U.S. Energy Information Administration, Washington, DC.

10. Archive Media and Installation Manual
    NEMS2010

11. Energy Systems Described
    The OGSM projects oil and natural gas production activities for six onshore and three offshore regions as well as three Alaskan regions. Exploratory and developmental drilling activities are treated separately, with exploratory drilling further differentiated as new field wildcats or other exploratory wells. New field wildcats are those wells drilled for a new field on a structure or in an environment never before productive. Other exploratory wells are those drilled in already productive locations. Development wells are primarily within or near proven areas and can result in extensions or revisions. Exploration yields new additions to the stock of reserves, and development determines the rate of production from the stock of known reserves.

12. Coverage
    Geographic: Six Lower 48 onshore supply regions, three Lower 48 offshore regions, and three Alaskan regions.
    Time Units/Frequency: Annually 1990 through 2035
    Product(s): Crude oil and natural gas
    Economic Sector(s): Oil and gas field production activities

13. Model Features
    Model Structure: Modular, containing four major components
    - Onshore Lower 48 Oil and Gas Supply Submodule
    - Offshore Oil and Gas Supply Submodule
    - Alaska Oil and Gas Supply Submodule
    - Oil Shale Supply Submodule

    Modeling Technique: The OGSM is a hybrid econometric/discovery process model. Drilling activities in the United States are projected using the estimated discounted cash flow that measures the expected present value profits for the proposed effort and other key economic variables.
    Special Features: Can run stand-alone or within the NEMS. Integrated NEMS runs employ short-term natural gas supply functions for efficient market equilibration.

14. Non-DOE Input Data
    - Alaskan Oil and Gas Field Size Distributions - U.S. Geological Survey
    - Alaska Facility Cost By Oil Field Size - U.S. Geological Survey
    - Alaska Operating cost - U.S. Geological Survey
    - Basin Differential Prices - Natural Gas Week, Washington, DC
    - State Corporate Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*
    - State Severance Tax Rate - Commerce Clearing House, Inc. *State Tax Guide*
    - Federal Corporate Tax Rate, Royalty Rate - U.S. Tax Code
    - Onshore Drilling Costs - (1.) American Petroleum Institute. *Joint Association Survey of Drilling Costs (1970-2008)*, Washington, D.C.; (2.) Additional unconventional gas recovery drilling and operating cost data from operating companies
    - Offshore Technically Recoverable Oil and Gas Undiscovered Resources - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)
    - Offshore Exploration, Drilling, Platform, and Production Costs - Department of Interior. Minerals Management Service (Correspondence from Gulf of Mexico and Pacific OCS regional offices)
    - Canadian Wells drilled - Canadian Association of Petroleum Producers. *Statistical Handbook*.

- Canadian Recoverable Resource Base - National Energy Board. *Canada's Conventional Natural Gas Resources: A Status Report*, Canada, April 2004.
- Canadian Reserves - Canadian Association of Petroleum Producers. *Statistical Handbook*.
- Unconventional Gas Resource Data - (1) USGS *1995 National Assessment of United States Oil and Natural Gas Resources*; (2) Additional unconventional gas data from operating companies
- Unconventional Gas Technology Parameters - (1) Advanced Resources International Internal studies; (2) Data gathered from operating companies

15. DOE Input Data
    - Onshore Lease Equipment Cost – U.S. Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 2008)*, DOE/EIA-0815(80-08)
    - Onshore Operating Cost – U.S. Energy Information Administration. *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations (1980 - 2008)*, DOE/EIA-0815(80-08)
    - Emissions Factors – U.S. Energy Information Administration
    - Oil and Gas Well Initial Flow Rates – U.S. Energy Information Administration, Office of Oil and Gas
    - Wells Drilled – U.S. Energy Information Administration, Office of Oil and Gas
    - Expected Recovery of Oil and Gas Per Well – U.S. Energy Information Administration, Office of Oil and Gas
    - Oil and Gas Reserves – U.S. Energy Information Administration. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, (1977-2009), DOE/EIA-0216(77-09)

16. Computing Environment
    - Hardware Used: PC
    - Operating System: Windows 95/Windows NT/Windows XP
    - Language/Software Used: FORTRAN
    - Memory Requirement: Unknown
    - Storage Requirement: Unknown
    - Estimated Run Time: 287 seconds

17. Reviews conducted
    - Independent Expert Review of the Offshore Oil and Gas Supply Submodule - Turkay Ertekin from Pennsylvania State University; Bob Speir of Innovation and Information Consultants, Inc.; and Harry Vidas of Energy and Environmental Analysis , Inc., June 2004
    - Independent Expert Review of the Annual Energy Outlook 2003 - Cutler J. Cleveland and Robert K. Kaufmann of the Center for Energy and Environmental Studies, Boston University; and Harry Vidas of Energy and Environmental Analysis, Inc., June-July 2003
    - Independent Expert Reviews, Model Quality Audit; Unconventional Gas Recovery Supply Submodule - Presentations to Mara Dean (DOE/FE - Pittsburgh) and Ray Boswell (DOE/FE - Morgantown), April 1998 and DOE/FE (Washington, DC)

18. Status of Evaluation Efforts

    Not applicable

19. Bibliography

    See Appendix B of this document.

Appendix D. Output Inventory

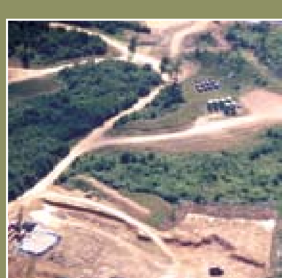
Variable Name	Description	Unit	Classification	Passed To Module
OGANGTSMX	Maximum natural gas flow through ANGTS	BCF	NA	NGTDM
OGCCAPPRD	Coalbed Methane production from CCAP		17 OGSM/NGTDM regions	NGTDM
OGCOPRD	Crude production by oil category	MMbbl/day	10 OGSM reporting regions	Industrial
OGCOPRDGOM	Gulf of Mexico crude oil production	MMbbl/day	Shallow and deep water regions	Industrial
OGCOWHP	Crude wellhead price by oil category	87$/bbl	10 OGSM reporting regions	Industrial
OGCNQPRD	Canadian production of oil and gas	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGCNPPRD	Canadian price of oil and gas	oil:87$/ bbl gas:87$/ BCF	Fuel (oil, gas)	NGTDM
OGCORSV	Crude reserves by oil category	Bbbl	5 crude production categories	Industrial
OGCRDSHR	Crude oil shares by OGSM region and crude type	percent	7 OLOGSS regions	PMM
OGDNGPRD	Dry gas production	BCF	57 Lower 48 onshore & 6 Lower 48 offshore districts	PMM
OGELSCO	Oil production elasticity	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGELSHALE	Electricity consumed	Trillion Btu	NA	Industrial
OGELSNGOF	Offshore nonassociated dry gas production elasticity	fraction	3 Lower 48 offshore regions	NGTDM
OGELSNGON	Onshore nonassociated dry gas production elasticity	fraction	17 OGSM/NGTDM regions	NGTDM
OGEORFTDRL	Total footage drilled from CO2 projects	feet	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORINJWLS	Number of injector wells from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORNEWWLS	Number of new wells drilled from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORPRD	EOR production from CO2 projects	Mbbl	7 OLOGSS regions 13 CO2 sources	Industrial
OGEORPRDWLS	Number of producing wells from CO2 projects	wells	7 OLOGSS regions 13 CO2 sources	Industrial
OGEOYAD	Unproved Associated-Dissolved gas resources	TCF	6 Lower 48 onshore regions	Industrial
OGEOYRSVON	Lower 48 Onshore proved reserves by gas category	TCF	6 Lower 48 onshore regions 5 gas categories	Industrial
OGEOYINF	Inferred oil and conventional NA gas reserves	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial

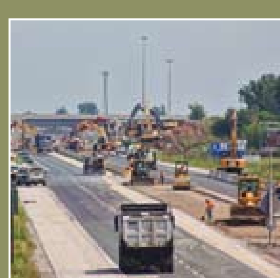
Variable Name	Description	Unit	Classification	Passed To Module
OGEOYRSV	Proved Crude oil and natural gas reserves	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGEOYUGR	Technically recoverable unconventional gas resources	TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGEOYURR	Undiscovered technically recoverable oil and conventional NA gas resources	Oil: Bbbl Gas: TCF	6 Lower 48 onshore & 3 Lower 48 offshore regions	Industrial
OGGROWFAC	Factor to reflect expected future cons growth		NA	NGTDM
OGJOBS			NA	Macro
OGNGLAK	Natural Gas Liquids from Alaska	Mbbl/day	NA	PMM
OGNGPRD	Natural Gas production by gas category	TCF	10 OGSM reporting regions	Industrial
OGNGPRDGOM	Gulf of Mexico Natural Gas production	TCF	Shallow and deep water regions	Industrial
OGNGRSV	Natural gas reserves by gas category	TCF	12 oil and gas categories	Industrial
OGNGWHP	Natural gas wellhead price by gas category	87$/MCF	10 OGSM reporting regions	Industrial
OGNOWELL	Wells completed	wells	NA	Industrial
OGPCRWHP	Crude average wellhead price	87$/bbl	NA	Industrial
OGPNGEXP	NG export price by border	87$/MCF	26 Natural Gas border crossings	NGTDM
OGPNGWHP	Natural gas average wellhead price	87$/MCF	NA	Industrial
OGPPNGIMP	NG import price by border	87$/MCF	26 Natural Gas border crossings	NGTDM
OGPRCEXP	Adjusted price to reflect different expectation		NA	NGTDM
OGPRCOAK	Alaskan crude oil production	Mbbl	3 Alaska regions	NGTDM
OGPRDADOF	Offshore AD gas production	BCF	3 Lower 48 offshore regions	NGTDM
OGPRDADON	Onshore AD gas production	BCF	17 OGSM/NGTDM regions	NGTDM
OGPRDUGR	Lower 48 unconventional natural gas production	BCF	6 Lower 48 regions and 3 unconventional gas types	NGTDM
OGPRRCAN	Canadian P/R ratio	fraction	Fuels (oil, gas)	NGTDM
OGPRRCO	Oil P/R ratio	fraction	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGPRRNGOF	Offshore nonassociated dry gas P/R ratio	fraction	3 Lower 48 offshore regions	NGTDM
OGPRRNGON	Onshore nonassociated dry gas P/R ratio	fraction	17 OGSM/NGTDM regions	NGTDM
OGQANGTS	Gas flow at U.S. border from ANGTS	BCF	NA	NGTDM
OGQCRREP	Crude production by oil category	MMbbl	5 crude production categories	PMM
OGQCRRSV	Crude reserves	Bbbl	NA	Industrial
OGQNGEXP	Natural gas exports	BCF	6 US/Canada & 3 US/Mexico border crossings	NGTDM

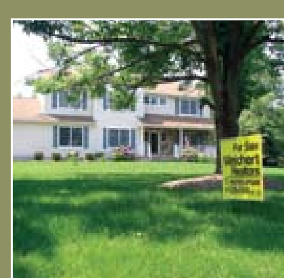
Variable Name	Description	Unit	Classification	Passed To Module
OGQNGIMP	Natural gas imports	BCF	3 US/Mexico border crossings; 4 LNG terminals	NGTDM
OGQNGREP	Natural gas production by gas category	TCF	12 oil and gas categories	NGTDM
OGQNGRSV	Natural gas reserves	TCF	NA	Industrial
OGRADNGOF	Non Associated dry gas reserve additions, offshore	BCF	3 Lower 48 offshore regions	NGTDM
OGRADNGON	Non Associated dry gas reserve additions, onshore	BCF	17 OGSM/NGTDM regions	NGTDM
OGRESCAN	Canadian end-of-year reserves	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGRESCO	Oil reserves	MMB	6 Lower 48 onshore & 3 Lower 48 offshore regions	PMM
OGRESNGOF	Offshore nonassociated dry gas reserves	BCF	3 Lower 48 offshore regions	NGTDM
OGRESNGON	Onshore nonassociated dry gas reserves	BCF	17 OGSM/NGTDM regions	NGTDM
OGSHALENG	Gas produced	BCF	NA	NGTDM
OGTAXPREM	Canadian tax premium	oil: MMB gas: BCF	Fuel (oil, gas)	NGTDM
OGTECHON	Technology factors	BCF	3 cost categories, 6 fuel types	Industrial
OGWPTDM	Natural Gas wellhead price	87$/MCF	17 OGSM/NGTDM regions	NGTDM

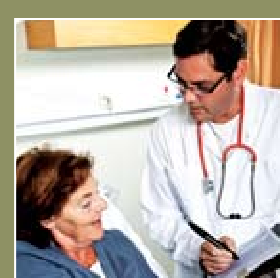
The Costs of Fracking

The Price Tag of Dirty Drilling's Environmental Damage









The Costs of Fracking

The Price Tag of Dirty Drilling's Environmental Damage

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Table of Contents

Infographic design: Jenna Leschuk

Executive Summary

Over the past decade, the oil and gas industry has fused two technologies—hydraulic fracturing and horizontal drilling—to unlock new supplies of fossil fuels in underground rock formations across the United States. "Fracking" has spread rapidly, leaving a trail of contaminated water, polluted air, and marred landscapes in its wake. In fact, a growing body of data indicates that fracking is an environmental and public health disaster in the making.

However, the true toll of fracking does not end there. Fracking's negative impacts on our environment and health come with heavy "dollars and cents" costs as well. In this report, we document those costs—ranging from cleaning up contaminated water to repairing ruined roads and beyond. Many of these costs are likely to be borne by the public, rather than the oil and gas industry. As with the damage done by previous extractive booms, the public may experience these costs for decades to come.

The case against fracking is compelling based on its damage to the environment and our health alone. To the extent that fracking does take place, the least the public can expect is for the oil and gas industry to be held accountable for the damage it causes. Such accountability must include up-front financial assurances sufficient to ensure that the harms caused by fracking are fully redressed.

Fracking damages the environment, threatens public health, and affects communities in ways that can impose a multitude of costs:

Drinking water contamination – Fracking brings with it the potential for spills, blowouts and well failures that contaminate groundwater supplies.

- Cleanup of drinking water contamination is so expensive that it is rarely even attempted. In Dimock, Pennsylvania, Cabot Oil & Gas reported having spent $109,000 on systems to remove methane from well water for 14 local households, while in Colorado, cleanup of an underground gas seep has been ongoing for eight years at a likely cost of hundreds of thousands of dollars, if not more.

- The provision of temporary replacement water supplies is also expensive. Cabot Oil & Gas reported having spent at least $193,000 on replacement water for homes with contaminated water in Dimock, Pennsylvania.

- Fracking can also pollute drinking water sources for major municipal systems, increasing water treatment costs. If fracking were to degrade the New York City watershed with sediment or other pollution, construction of a filtration plant would cost approximately $6 billion.

Health problems – Toxic substances in fracking fluid and wastewater—as well as air pollution from trucks, equipment and the wells themselves—have been linked to a variety of negative health effects.

- The National Institute of Occupational Safety and Health recently warned that workers may be at elevated risk of contracting the lung disease silicosis from inhalation of silica dust at fracking sites. Silicosis is one of a family of dust-induced occupational ailments that imposed $50 million medical care costs in the United States in 2007.

- Residents living near fracking sites have long suffered from a range of health problems, including headaches, eye irritation, respiratory problems and nausea—potentially imposing economic costs ranging from health care costs to workplace absenteeism and reduced productivity.

- Fracking and associated activities also produce pollution that contributes to the formation of ozone smog and particulate soot. Air pollution from gas drilling in Arkansas' Fayetteville Shale region imposed estimated public health costs of more than $10 million in 2008.

Natural resources impacts – Fracking converts rural and natural areas into industrial zones, replacing forest and farm land with well pads, roads, pipelines and other infrastructure, and damaging precious natural resources.

- The clearance of forest land in Pennsylvania for fracking could lead to increased delivery of nutrient pollution to the Chesapeake Bay, which already suffers from a vast nutrient-generated dead zone. The cost of reducing the same amount of pollution as could be generated by fracking would be approximately $1.5 million to $4 million per year.

- Gas operations in Wyoming have fragmented key habitat for mule deer and pronghorn, which are important draws for the state's $340 million hunting and wildlife watching industries. The mule deer population in one area undergoing extensive gas extraction dropped by 56 percent between 2001 and 2010.

- Fracking also produces methane pollution that contributes to global warming. Emissions of methane during well completion from each uncontrolled fracking well impose approximately $130,000 in social costs related to global warming.

Impacts on public infrastructure and services – Fracking strains infrastructure and public services and imposes cleanup costs that can fall on taxpayers.

- The truck traffic needed to deliver water to a single fracking well causes as much damage to local roads as nearly 3.5 million car trips. The state of Texas has approved $40 million in funding for road repairs in the Barnett Shale region, while

Pennsylvania estimated in 2010 that $265 million would be needed to repair damaged roads in the Marcellus Shale region.

- The need for vast amounts of water for fracking is helping to drive demand for new water infrastructure in arid regions of the country. Texas' official State Water Plan calls for the expenditure of $400 million on projects to support the mining sector over the next 50 years, with fracking projected to account for 42 percent of mining water use by 2020.

- The oil and gas industry has left thousands of orphaned wells from previous fossil fuel booms. Taxpayers may wind up on the hook for the considerable expense of plugging and reclaiming orphaned wells—Cabot Oil & Gas claims to have spent $730,000 per well to cap three shale gas wells in Pennsylvania.

- Fracking brings with it increased demands for public services. A 2011 survey of eight Pennsylvania counties found that 911 calls had increased in seven of them, with the number of calls increasing in one county by 49 percent over three years.

Broader economic impacts – Fracking can undercut the long-term economic prospects of areas where it takes place. A 2008 study found that Western counties that have relied on fossil fuel extraction are doing worse economically compared with peer communities and are less well-prepared for growth in the future.

- Fracking can affect the value of nearby homes. A 2010 study in Texas concluded that houses valued at more than $250,000 and within 1,000 feet of a well site saw their values decrease by 3 to 14 percent.

- Fracking has several negative impacts on farms, including the loss of livestock due to exposure to spills of fracking wastewater, increased difficulty in obtaining water supplies for farming, and potential conflicts with organic agriculture. In Pennsylvania, the five counties with the heaviest Marcellus Shale drilling activity saw an 18.5 percent reduction in milk production between 2007 and 2010.

As with previous fossil fuel booms that left long-term impacts on the environment, there is every reason to believe that the public will be stuck with the bill for many of the impacts of fracking.

Defining "Fracking"

In this report, when we refer to the impacts of "fracking," we include impacts resulting from all of the activities needed to bring a well into production using hydraulic fracturing, to operate that well, and to deliver the gas or oil produced from that well to market. The oil and gas industry often uses a more restrictive definition of "fracking" that includes only the actual moment in the extraction process when rock is fractured—a definition that obscures the broad changes to environmental, health and community conditions that result from the use of fracking in oil and gas extraction.

- Existing legal rules are inadequate to protect the public from the costs imposed by fracking. Current bonding requirements fail to assure that sufficient funds will be available for the proper closure and reclamation of well sites, and do nothing at all to ensure that money is available to fix other environmental problems or compensate victims. Further, weak bonding requirements fail to provide an adequate incentive for drillers to take steps to prevent pollution before it occurs.

- Current law also does little to protect against impacts that emerge over a long period of time, have diffuse impacts over a wide area, or affect health in ways that are difficult to prove with the high standard of certainty required in legal proceedings.

The environmental, health and community impacts of fracking are severe and unacceptable. Yet the dirty drilling practice continues at thousands of sites across the nation. Wherever fracking does occur, local, state and federal governments should at least:

- **Comprehensively restrict and regulate** fracking to reduce its environmental, health and community impacts as much as possible.

- Ensure **up-front financial accountability** by requiring oil and gas companies to post dramatically higher bonds that reflect the true costs of fracking.

Introduction

In Appalachia, more than 7,500 miles of streams are polluted with acid mine drainage—the legacy of coal mining. Many of those streams still run orange-colored and lifeless decades after mining ended. The ultimate cost of cleaning up acid mine drainage in Pennsylvania alone has been estimated at $5 billion.[1]

Texas has more than 7,800 orphaned oil and gas wells—wells that were never properly closed and whose owners, in many cases, no longer exist as functioning business entities.[2] These wells pose a continual threat of groundwater pollution and have cost the state of Texas more than $247 million to plug.[3]

In the western United States, uranium mining and milling have contaminated both water and land. The cost to taxpayers of cleaning up the uranium mills has been estimated at $2.3 billion, while the cost of cleaning up abandoned mines has been estimated at $14 million per mine.[4]

Over and over again, throughout American history, short-term resource extraction booms have left a dirty long-term legacy, imposing continuing costs on people and the environment years or decades after those who profited from the boom have left the scene.

Today, America is in the midst of a new resource extraction boom, one driven by a process colloquially known as "fracking." In just over a decade, fracking has spread across the country, unlocking vast supplies of previously inaccessible oil and gas from underground rock formations.

The costs of fracking—in environmental degradation, in illness, and in impacts on infrastructure and communities—are only just now beginning to be understood and tallied. It is also now becoming clear that the nation's current system of safeguards is incapable of protecting the public from having to shoulder those sizable costs in the years and decades to come.

The burdens imposed by fracking are significant, and the dangers posed to the environment and public health are great. If fracking is to continue, the least the American people should expect is for our laws to ensure that those who reap the benefits also bear its full costs.

The landscapes of Appalachia, Texas and the American West are living testaments to the need to hold industries accountable for cleaning up the damage they cause. As fracking unleashes yet another extractive boom, the time has come to ensure that this history does not repeat itself in the 21st century.

Fracking: The Process and its Impacts

Over the past decade, the oil and gas industry has married two technologies—horizontal drilling and hydraulic fracturing—to create a potent new combination that is being used to tap fossil fuels locked in previously difficult-to-reach rock formations across the United States. This technology, known as high-volume horizontal hydraulic fracturing—or, colloquially, "fracking"—has broad implications for the environment and public health.

Defining "Fracking"

Public debates about fracking often descend into confusion and contradiction due to a lack of clarity about terms. To the oil and gas industry, which seeks to minimize the perceived impacts, "fracking" refers only to the actual moment in the extraction process where rock is fractured by pumping fluid at high pressure down the well bore. Limiting the definition of fracking in this way also allows the oil and gas industry to include its long history of using hydraulic fracturing in traditional, vertical wells—a process with fewer impacts than the technology being used in oil and gas fields today—to create a false narrative about the safety of fracking. It is only according to this carefully constructed definition that ExxonMobil CEO Rex Tillerson could say, as he did in a Congressional hearing in 2011, that "[t]here have been over a million wells hydraulically fractured in the history of the industry, and there is not one, not one, reported case of a freshwater aquifer having ever been contaminated from hydraulic fracturing."[5]

Just as only a small portion of an iceberg is visible above the water, only a small portion of the impacts of fracking are the direct result of fracturing rock. Each step in the process of extracting oil or gas from a fracked well has impacts on the environment, public health and communities. Thus, any reasonable assessment of fracking ***must*** include the full cycle of extraction operations before and after the moment where rock is cracked open with fluid under high pressure.

In this report, when we refer to the impacts of "fracking," we include impacts resulting from all of the activities needed to bring a well into production using hy-

Fracking imposes a range of environmental, health and community impacts. Above, a fracking well site is built in a forested area of Wetzel County, W.Va. Credit: Robert Donnan

draulic fracturing, to operate that well, and to deliver the gas or oil extracted from that well to market.

The Fracking Process

Fracking is used to unlock gas or oil trapped in underground rock formations, allowing it to flow to the surface, where it can be captured and delivered to market. Fracking combines hydraulic fracturing, which uses a high-pressure mixture of water, sand and chemicals to break up underground rock formations, with horizontal drilling, which enables drillers to fracture large amounts of rock from a single well.

The combination of hydraulic fracturing with horizontal drilling has magnified the environmental impacts of oil and gas extraction. Whereas traditional, low-volume hydraulic fracturing used tens of thousands of gallons of water per well, today's high-volume hydraulic fracturing operations use millions of gallons of water, along with a different combination of sand and chemical additives, to extract gas or oil.

A vast amount of activity—much of it with impacts on the environment and nearby communities—is necessary to bring a fracking well into production and to deliver the gas extracted from that well to market. Among those steps are the following:

Well Site Preparation and Road Construction

Before drilling can begin, several acres of land must be cleared of vegetation and leveled to accommodate drilling equipment, gas collection and processing equipment, and vehicles. Additional land must be cleared for roads to the well site, as well as for any pipelines needed to deliver gas to market.

Materials Assembly

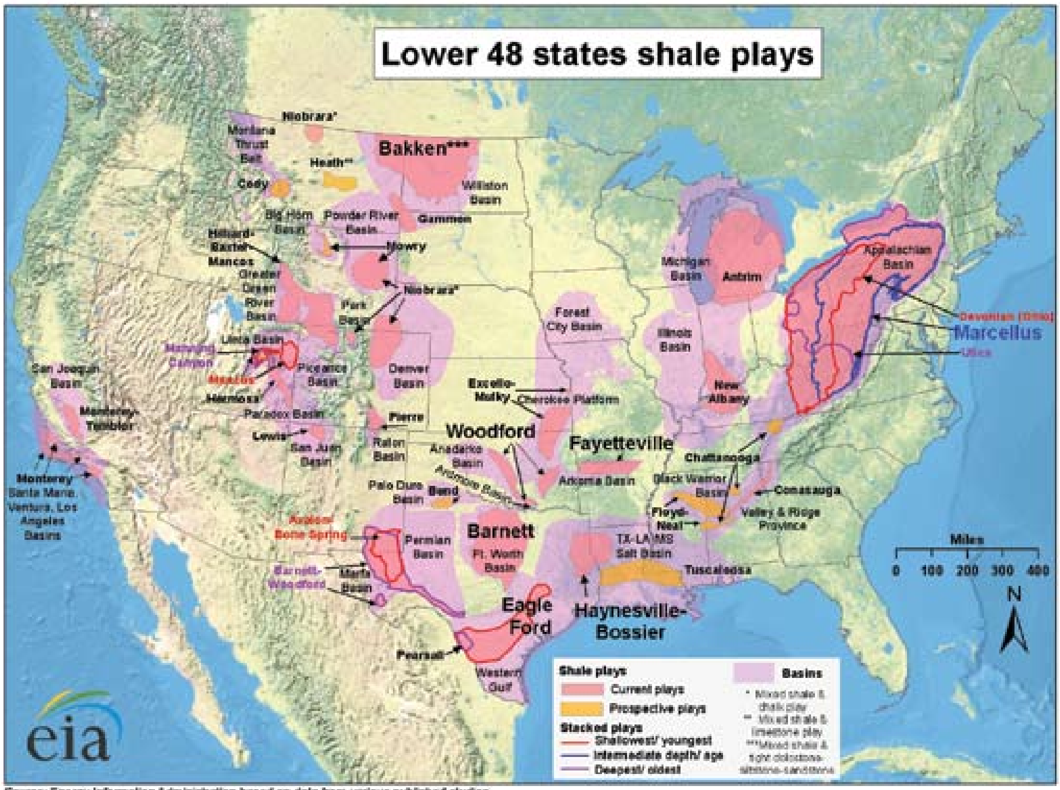
Hydraulic fracturing requires massive amounts of water, sand and chemicals—all of which must be obtained and delivered to the well site. Water for fracking comes either from surface waterways, groundwater or recycled wastewater from previous fracking activities, with millions of gallons of water required for each well. The special grade of sand used in fracking must be extracted from the ground—often from silica mines in the upper Midwest—and transported to the well site. Water, sand and other materials must be carried to well sites in trucks, tearing up local roads, creating congestion, and producing local level air pollution.

Drilling and Hydraulic Fracturing

Once the necessary machinery and materials are assembled at the drilling site, drilling can begin. The well is drilled to the depth of the formation that is being targeted. In horizontally drilled wells, the well bore is turned roughly 90 degrees to extend along the length of the formation. Steel "casing" pipes are inserted to stabilize and contain the well, and the casing is cemented into place. A mix of water, sand and chemicals is then injected at high pressure—the pressure causes the rock formation to crack, with the sand propping open the gaps in the rock. Some of the injected water then flows back out of the well when the pressure is released ("flowback" water), followed by gas and water from the formation ("produced water").

Equipment is put in place in preparation for hydraulic fracturing at a well site in Troy, Pa. In hydraulic fracturing, a combination of water, sand and chemicals is injected at high pressure to fracture oil or gas-bearing rock formations deep underground. Credit: New York Department of Environmental Conservation

Figure 1. Shale Gas and Oil Plays[6]



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Gas Processing and Delivery

As natural gas flows from the fracked well, it must be collected, purified and compressed for injection into pipelines and delivery to market.

Wastewater Management and Disposal

Flowback and produced water must be collected and disposed of safely. Wastewater from fracking wells is often stored onsite temporarily in retention ponds or tanks. From there, the fluid may be disposed of in an underground injection well or an industrial wastewater treatment plant, or it may be treated and re-used in another fracking job.

Plugging and Reclamation

To prevent future damage to the environment and drinking water supplies, wells must be properly plugged and the land around them restored to something approaching its original vegetated condition. This involves plugging the well with cement, removing all unnecessary structures from the well pad, and replanting the area.

Fracking and the New Gas/Oil Rush

From its beginnings in the Barnett Shale region of Texas at the turn of the 21^{st} century, the use of fracking has spread across the United States with breathtaking speed. A decade later, the combination of high-volume hydraulic fracturing with horizontal drilling has been used in thousands of oil and gas wells across the country—despite persistent questions about the impact of the technology and supporting activities on the environment, public health and communities.

Roughy half of U.S. states, stretching from New York to California, sit atop shale or other rock formations with the potential to produce oil or gas using fracking. As fracking has made oil and gas extraction viable in more of these formations, it is bringing drilling closer to greater numbers of people as well as precious natural resources.

- Between 2003 and 2010, more than 11,000 wells were drilled in the Fort Worth basin of Texas' Barnett Shale formation.[7] The Barnett Shale underlies one of the most populous regions of the state—the Dallas-Fort Worth Metroplex—and drilling has taken place in urban and suburban neighborhoods of the region.

- In Pennsylvania's Marcellus Shale, more than 6,300 shale gas wells have been drilled since 2000; permits have been issued that would allow for more than 2,400 additional wells to be drilled.[8] A 2011 analysis by PennEnvironment Research & Policy Center found that 104 day care centers and 14 schools in Pennsylvania were located within a mile of a shale gas well; that figure is certainly higher today.[9]

- In Colorado, fracking has taken off in the oil-producing Niobrara Shale formation. Weld County, Colorado, located just north of Denver and just east of Fort Collins, has seen the permitting of more than 1,300 horizontal wells since the beginning of 2010.[10]

Oil and gas companies are aggressively seeking to expand fracking to places where more people live (including the city of Dallas) and to treasured natural areas (including the Delaware River Basin, which provides drinking water for 15 million people). Wherever this new gas rush is allowed, it will impose significant impacts on the environment, public health and communities. To add insult to injury, these impacts also come with heavy price tags that will all too often be borne by individual residents and their communities. The following section of this report provides a breakdown of fracking impacts along with examples of the real-life costs already being imposed on America's environment and our communities.

The Costs of Fracking

A great deal of public attention has been focused on the immediate impacts of fracking on the environment, public health and communities. Images of flaming water from faucets, stories of sickened families, and incidents of blowouts, spills and other mishaps have dramatically illustrated the threats posed by fracking.

Less dramatic, but just as important, are the long-term implications of fracking—including the economic burdens imposed on individuals and communities. In this paper, we outline the many economic costs imposed by fracking and show that, absent greatly enhanced mechanisms of financial assurance, individuals, communities and states will be left to bear many of those costs.

Residents of Dimock, Pennsylvania, are among those who have reported drinking water contamination in the wake of nearby fracking activity. Here, discolored water from local wells illustrates the change in water quality following fracking. Photo: Hudson Riverkeeper

Drinking Water Contamination

Fracking can pollute both groundwater and surface waterways such as rivers, lakes and streams. In rural areas, where the bulk of fracking takes place, residents may rely on groundwater for household and agricultural use. Alternative sources of water—such as municipal water supplies—may be unavailable or prohibitively expensive.

Fracking has polluted drinking water sources in a variety of ways.

- Spills and well blowouts have released fracking chemicals and flowback or produced water to groundwater and surface water. In Colorado and New Mexico, an estimated 1.2 to 1.8 percent of all gas drilling projects result in groundwater contamination.[11]

- Waste pits containing flowback and produced water have frequently failed. In New Mexico, substances from oil and gas pits have contaminated groundwater at least 421 times.[12]

- Faulty well construction has caused methane and other substances to find their way into groundwater.[13]

Recent studies have suggested that fracking may also pose a longer-term threat of groundwater contamination. One study used computer modeling to conclude that natural faults and fractures in the Marcellus Shale region could accelerate the movement of fracking chemicals—possibly bringing these contaminants into contact with groundwater in a matter of years.[14] In addition, a recent study by researchers at Duke University found evidence for the existence of underground pathways between the deep underground formations tapped by Marcellus Shale fracking and groundwater supplies closer to the surface.[15] The potential for longer-term groundwater contamination from fracking is particularly concerning, as it raises the possibility that contamination will become apparent only long after the drillers responsible have left the scene.

Among the costs that result from drinking water contamination are the following:

Groundwater Cleanup

Groundwater is a precious and often limited natural resource. Once contaminated, it can take years, decades or even centuries for groundwater sources to clean themselves naturally.[16] As a result, the oil and gas industry must be held responsible for restoring groundwater supplies to their natural condition.

Methane contamination of well water poses a risk of explosion and is often addressed by removing it from water at the point of use. In Dimock, Pennsylvania, Cabot Oil & Gas reported having spent $109,000 on methane removal systems for 14 local households in the wake of drilling-related methane contamination of local groundwater supplies. In addition, the company spent $10,000 on new or extended vent stacks to prevent the build-up of methane gas in residents' homes.[17] Such measures do not remove methane from groundwater supplies, but merely eliminate the immediate threat to residents' homes.

"In Dimock, Pennsylvania, Cabot Oil & Gas reported having spent $109,000 on methane removal systems for 14 households."

Removing other toxic contaminants from groundwater is so costly that it it rarely attempted, with costs of hundreds of thousands of dollars or more.

In 2004, improper cementing of a fracking well in Garfield County, Colorado, caused natural gas to vent for 55 days into a fault terminating in a surface waterway, West Divide Creek.[18] In response to the leak, the company responsible for drilling the well, Encana, engaged in regular testing of nearby wells and installed equipment that injects air into the groundwater, enabling chemical contaminants in the water to become volatile and be removed from the water, using a process known as air sparging. These activities began in 2004 and were still ongoing as of mid-2012.[19]

The cost of groundwater remediation in the Garfield County case is unknown, but likely runs into the hundreds of thousands of dollars, if not more. A 2004 Environmental Protection Agency (EPA) document, referring to the work of a federal roundtable on environmental cleanup technologies, estimated the cost of air sparging at $150,000 to $350,000 per acre.[20] Adjusting for inflation, and assuming that the extent of the seep was correctly estimated by Encana at 1.3 acres, one could estimate the cost of the sparging operation in 2012 dollars at $248,000 to $579,000.[21] In addition, as of May 2012, Encana and its contractors had collected more than 1,300 water samples since the seep began.[22] Again, the cost of this sampling and testing is unknown, but could be conservatively estimated to be in the tens of thousands of dollars. Cabot Oil & Gas, for example, incurred $700,000 in water testing expenses in the wake of concerns about groundwater contamination from a fracking well in Dimock, Pennsylvania.[23]

The Colorado example shows that the process of cleaning up contaminated groundwater can take years to complete, underscoring the need for protections to ensure that drillers have the financial wherewithal to fulfill their obligations to clean up pollution.

Water Replacement

As noted above, the process of cleaning up contaminated groundwater can take years. In the meantime, residents must be provided with clean, temporary sources of drinking water.

"Cabot Oil & Gas provided at least $193,000 worth of water to homes affected by contamination."

The Colorado and Pennsylvania examples above demonstrate the high cost of supplying replacement water to households dependent on contaminated wells. In Colorado, Encana offered "complete water systems and potable water delivery" to homes within a two-mile area of the West Divide Creek gas seep, at an estimated cost of $350,000.[24] These deliveries continued into 2006. In Pennsylvania, Cabot Oil & Gas provided at least $193,000 worth of water to homes affected by contamination there.[25] A permanent solution to water issues in Dimock—the extension of municipal water to the neighborhood—was estimated to cost $11.8 million.[26]

Water Treatment Costs Due to Surface Water Contamination

Fracking and related activities may reduce the quality of rivers and streams to the point where municipalities must invest in additional water treatment in order to make water safe to drink.

"Should gas drilling require drinking water to undergo additional treatment, New York would be required to build one of the world's largest filtration plants at an estimated cost of $6 billion."

The most significant impacts of fracking on rivers and streams used for drinking water come not from individual spills, blowouts or other accidents, but rather from the effects of fracking many wells in a given area at the same time. Widespread fracking can damage waterways through water withdrawals from river basins, the dumping of fracking wastewater into rivers, or increased sedimentation resulting from land clearance for well pads, pipelines and other natural gas infrastructure.

Damage from widespread fracking may require water utilities to invest in expensive additional treatment. New York City's water supply, for example, comes from upstate New York watersheds that are sufficiently pristine that water filtration is not required. Should gas drilling—or any other polluting activity—require additional treatment, New York would be required to build one

The disposal of fracking wastewater in open pits contributes to air pollution, while leakage from improperly lined pits has contaminated groundwater and surface water. Chemicals present in fracking wastewater have been linked to serious health problems, including cancer. Credit: Mark Schmerling

of the world's largest water filtration plants. New York has already had to take this step for one major source of drinking water, spending $3 billion to build a filtration plant for the part of the watershed east of the Hudson River.[27] The cost of doing the same for areas west of the Hudson, which sit atop the Marcellus Shale formation, was estimated in 2000 to be as much as $6 billion.[28]

Health Problems

Fracking produces pollution that affects the health of workers, nearby residents and even people living far away. Toxic substances in fracking chemicals and produced water, as well as pollution from trucks and compressor stations, have been linked to a variety of negative health effects. Chemical components of fracking fluids, for example, have been linked to cancer, endocrine disruption, and neurological and immune system problems.[29]

The legal system often offers little relief for those whose health is impacted by chemically tainted air or water. In order to prevail in court, an individual affected by exposure to toxic chemicals must prove that he or she has been exposed to a specific toxic chemical linked to the health effects that they are experiencing *and* that the exposure was caused by the defendant (as opposed to the many other sources of possible exposure to toxic chemicals that most people experience every day).[30] Meeting that high legal standard of proof is costly—usually requiring extensive medical and environmental testing and expert testimony—and difficult, given corporate attorneys' track record of exploiting gaps in scientific knowledge to cast doubt on claims of harm from toxic chemical exposures. As a result, many citizens whose health has been affected by fracking may be discouraged from taking their complaints to court.

Individuals and taxpayers, therefore—rather than polluters—may bear much of the financial burden for health costs resulting from fracking.

Nearby Residents Getting Sick

Emissions from fracking wellsites contain numerous substances that make people sick.

In Texas, monitoring by the Texas Department of Environmental Quality detected levels of benzene—a known cancer-causing chemical—in the air that were high enough to cause immediate human health concern at two sites in the Barnett Shale region, and at levels that pose long-term health concern at an additional 19 sites. Several chemicals were also found at levels that can cause foul odors.[31] Less extensive testing conducted by the Pennsylvania Department of Environmental Protection detected components of natural gas, particularly methane, in the air near Marcellus Shale drilling operations.[32] Air monitoring in Arkansas has also found elevated levels of volatile organic compounds (VOCs)—some of which are also hazardous air pollutants—at the perimeter of hydraulic fracturing sites.[33]

"Residents living near fracking sites have long suffered from a range of health problems, including headaches, eye irritation, respiratory problems and nausea—imposing economic costs ranging from health care costs to workplace absenteeism and reduced productivity."

Residents living near fracking sites have long suffered from a range of health problems, including headaches, eye irritation, respiratory problems and nausea.[34] In western Pennsylvania, for example, residents living near one fracking well site have complained of rashes, blisters and other health effects that they attribute to a wastewater impoundment.[35] An investigation by the investigative journalism website ProPublica uncovered numerous similar reports of illness in western states.[36]

A recent study by researchers at the Colorado School of Public Health found that residents living within a half-mile of natural gas wells in one area of Colorado were exposed to air pollutants that increased their risk of illness.[37] The report noted that "health effects, such as headaches and throat and eye irritation reported by residents during well completion activities occurring in Garfield County, are consistent with known health effects of many of the hydrocarbons evaluated in this analysis."[38]

These health impacts are unacceptable regardless of the economic cost. But they also have significant economic impacts, including:

- Health care costs, including inpatient, outpatient and prescription drug costs;
- Workplace absenteeism;
- "Presenteeism," or reduced productivity at work.[39]

Major health problems such as cancer are obviously costly. The average case of cancer in the United States in 2003 imposed costs in treatment and lost productivity of approximately $30,000.[40]

The economic impacts of less severe problems such as headaches and respiratory symptoms can also add up quickly. Each day of reduced activity costs the economy roughly $50 while a missed day of work costs approximately $105.[41] The economic value to individuals of avoiding one exposure to hydrocarbon odors per week is approximately $26 to $36 per household.[42] As fracking continues to spread, particularly in areas close to population centers, the number of residents affected by these health problems—already substantial—is likely to increase.

Worker Injury, Illness, and Death

Fracking is dangerous business for workers. Nationally, oil and gas workers are seven times more likely to die on the job than other workers, with traffic accidents, death from falling objects, and explosions the leading causes of death. Between 2003 and 2008, 648 oil and gas workers nationwide died from on-the-job injuries.[43] Workers at fracking well sites are vulnerable to many of these same dangers, as well as one that is specific to fracking: inhalation of silica sand.

Silica sand is used to prop open the cracks formed in underground rock formations during fracking. As silica is moved from trucks to the well site, silica dust can become airborne. Without adequate protection, workers who breathe in silica dust can develop an elevated risk of contracting silicosis, which causes swelling in the lungs, leading to the development of chronic

"The National Institute of Occupational Safety and Health recently warned that workers at fracking sites may be at risk of contracting the lung disease silicosis from inhalation of silica dust. Silicosis is one of a family of dust-induced occupational ailments that imposed $50 million in medical care costs in 2007."

Fracking can be a dangerous business for workers. The National Institute for Occupational Safety and Health recently found dangerous levels of airborne silica at fracking sites in several states, while workers also risk injury from traffic accidents, falling objects, explosions and other hazards. Workers, their families and the public often bear much of the costs of workplace illness and injury. Credit: Mark Schmerling cough and breathing difficulty.[44] Silica exposure can also cause lung cancer.[45]

A recent investigation by the National Institute for Occupational Safety and Health (NIOSH) found that workers at some fracking sites may be at risk of lung disease as a result of inhaling silica dust. The NIOSH investigation reviewed 116 air samples at 11 fracking sites in Arkansas, Colorado, North Dakota, Pennsylvania and Texas. Nearly half (47 percent) of the samples had levels of silica that exceeded the Occupational Safety and Health Administration's (OSHA) legal limit for workplace exposure, while 78 percent exceeded OSHA's recommended limits. Nearly one out of 10 (9%) of the samples exceeded the legal limit for silica by a factor of 10, exceeding the threshold at which half-face respirators can effectively protect workers.[46]

Silicosis is one of a family of dust-induced occupational ailments (including asbestosis and black lung disease) that have long threatened the health of industrial workers. A recent study estimated that this category of occupational disease imposed costs in medical care alone of $50 million in 2007.[47]

Workers, their families and taxpayers are often forced to pick up much of the cost of workplace illnesses and injuries. A 2012 study by researchers at the University of California, Davis, estimated that workers compensation insurance covers only about 20 percent of the total costs of workplace illness and injury, with government programs such as Medicaid and Medicare, as well as workers and their families, bearing much of the burden in health care costs and lost productivity.[48]

Air Pollution Far from the Wellhead

Air pollution from fracking also threatens the health of people living far from the wellhead—especially children, the elderly and those with respiratory disease.

Fracking produces a variety of pollutants that contribute to regional air pollution problems. VOCs in natural gas formations contribute to the formation of ozone "smog," which reduces lung function among healthy people, triggers asthma attacks, and has been linked to increases in school absences, hospital visits and premature death.[49] Some VOCs are also considered "hazardous air pollutants," which have been linked to cancer and other serious health effects. Emissions from trucks carrying water and materials to well sites, as well as from compressor stations and other fossil fuel-fired machinery, also contribute to the formation of smog and soot that threatens public health.

"Air pollution from drilling in Arkansas' Fayetteville Shale in 2008 likely imposed public health costs greater than $10 million in 2008."

Fracking is a significant source of air pollution in areas experiencing large amounts of drilling. A 2009 study in five Dallas-Fort Worth-area counties experiencing heavy Barnett Shale drilling activity found that oil and gas production was a larger source of smog-forming emissions than cars and trucks.[50] Completion of a single uncontrolled natural gas well produces approximately 22.7 tons of volatile organic compounds (VOC) per well—equivalent to the annual VOC emissions of about 7,000 cars—as well as 1.7 tons of hazardous air pollutants and approximately 156 tons of methane, which contributes to global warming.[51]

Well operations, storage of natural gas liquids, and other activities related to fracking add to the pollution toll, playing a significant part in regional air pollution problems. In Arkansas, for example, gas production in the Fayetteville Shale region was estimated to be responsible for

2.6 percent of the state's total emissions of nitrogen oxides (NO_x).[52] An analysis conducted for New York State's revised draft environmental impact statement on Marcellus Shale drilling posited that, in a worst case scenario of widespread drilling and lax emission controls, shale gas production could add 3.7 percent to state NO_x emissions and 1.3 percent to statewide VOC emissions compared with 2002 emissions levels.[53]

The public health costs of pollution from fracking are significant. The financial impact of ozone smog on public health has been estimated at $1,648 per ton of NO_x and VOCs.[54] Applying those costs to emissions in five counties of the Dallas-Fort Worth region with significant Barnett Shale drilling, the average public health cost of those emissions would be more than $270,000 *per day* during the summer ozone season.[55] In Arkansas, the nearly 6,000 tons of NO_x and VOCs emitted in 2008 would impose an annual public health cost of roughly $9.8 million.[56]

Various aspects of fracking also create particulate—or soot—pollution. A 2004 EPA regulatory impact analysis for new standards for stationary internal combustion engines often used on natural gas pipelines and in oil and gas production, for example, estimated the benefit of reducing one ton of particulates under 10 microns in diameter (PM_{10}) at $8,028 per ton.[57] Using this figure, the economic benefit of eliminating PM_{10} emissions from Arkansas' Fayetteville Shale would be roughly $5.4 million per year.

Air pollution from drilling in Arkansas' Fayetteville Shale in 2008, therefore, likely imposed public health costs greater than $10 million in 2008, with additional, unquantified costs imposed in the form of lost agricultural production and lower visibility.

Damage to Natural Resources

Fracking threatens valuable natural resources all across the country. Fracking converts rural and natural areas into industrialized zones, with forests and agricultural land replaced by well pads, roads, pipelines and natural gas infrastructure. The effects of this development are more than just aesthetic, as economists have increasingly come to recognize the value of the services that natural systems provide to people and the economy.

Threats to Our Rivers and Streams

Damage to aquatic ecosystems has a direct, negative impact on the economy. The loss of a recreational or commercial fishery due to spills, excessive withdrawals of water, or changes in water quality caused by the cumulative effects of fracking in an area can have devastating impacts on local businesses.

"The clearance of forest land in Pennsylvania for fracking could lead to increased delivery of nutrient pollution to the Chesapeake Bay, which suffers from a nutrient-generated dead zone. The cost of reducing an amount of pollution equivalent to that produced by fracking would be approximately $1.5 million to $4 million per year."

In Pennsylvania, for example, fishing had an estimated economic impact of $1.6 billion in 2001.[58] Allocating that impact to the roughly 13.4 million fishing trips taken in Pennsylvania each year (as of the late 1990s) would result in an estimated impact of $119 per trip.[59]

The Monongahela River, shown here at Rices Landing, Pa., has been affected by discharges of fracking wastewater and by water withdrawals for fracking. A 2011 Army Corps of Engineers report concluded that "the quantity of water withdrawn from streams [in the Monongahela watershed] is largely unregulated and is beginning to show negative consequences." Credit: Jonathan Dawson

Spills, blowouts and other accidents related to fracking have caused numerous fish kills in Pennsylvania. In 2009, a pipe containing freshwater and flowback water ruptured in Washington County, Pennsylvania, triggering a fish kill in a tributary of Brush Run, which is part of a high-quality watershed.[60] That same year, in the same county, another pipe rupture at a well drilled in a public park killed fish and other aquatic life along a three-quarter-mile length of a local stream.[61]

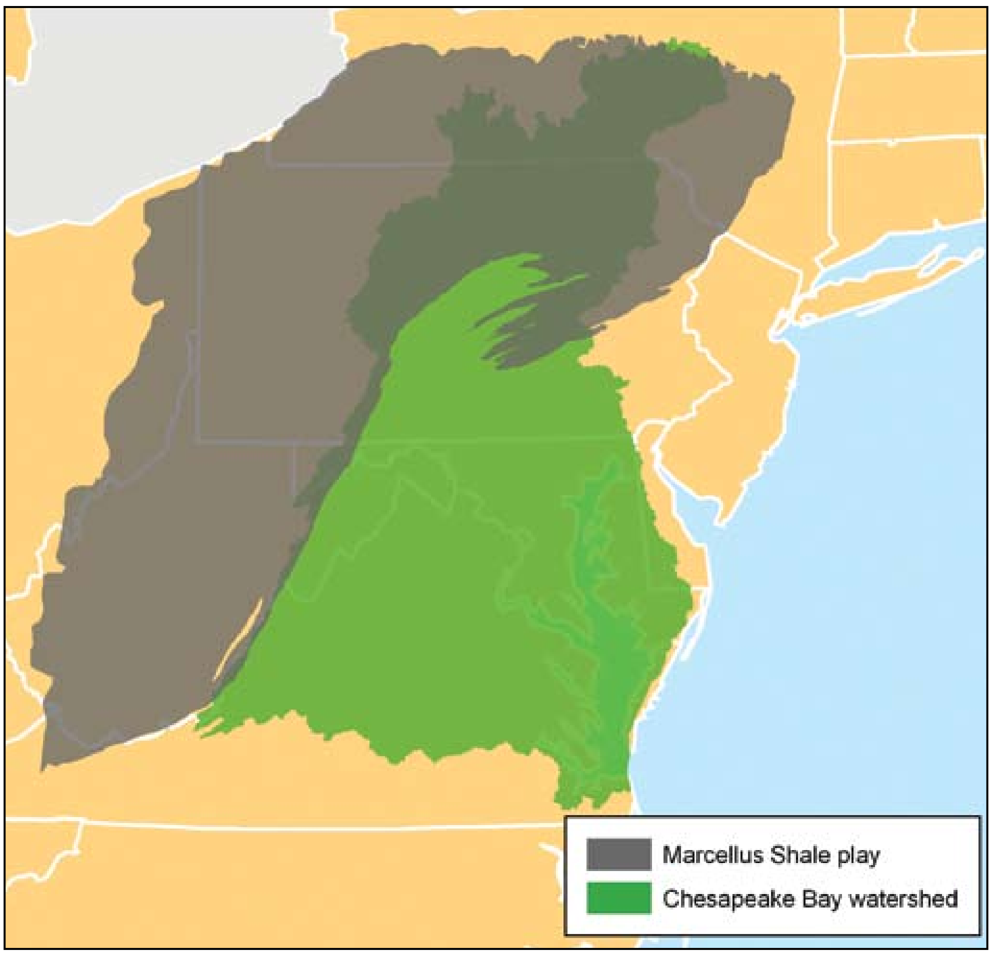
The clearing of land for well pads, roads and pipelines can increase sedimentation of nearby waterways and degrade the ability of natural landscapes to retain nutrients. A recent preliminary study by the Academy of Natural Sciences of Drexel University found an association between increased density of natural gas drilling activity and degradation of ecologically important headwaters streams.[62]

Excessive water withdrawals also play havoc with the ecology of rivers and streams. In Pennsylvania, water has been illegally withdrawn for fracking numerous times, to the extent of streams being sucked dry. Two streams in southwestern Pennsylvania—Sugarcamp Run and Cross Creek—were reportedly drained for water withdrawals, triggering fish kills.[63]

Water withdrawals also concentrate pollutants, reducing water quality. A 2011 U.S. Army Corps of Engineers study of the Monongahela River basin of Pennsylvania and West Virginia concluded that, "The quantity of water withdrawn from streams is largely unregulated and is beginning to show negative consequences."[64] The Corps report noted that water is increasingly being diverted from the relatively clean streams that flow into Corps-maintained reservoirs, limiting the ability of the Corps to release clean water to help dilute pollution during low-flow periods.[65] It described the water supply in the Monongahela basin as "fully tapped."[66]

On a broader scale, the clearance of forested land for well pads, roads and pipelines reduces the ability of the land to prevent pollution from running off into rivers and streams. Among the waterways most affected by runoff pollution is the Chesapeake Bay, where excessive runoff of nutrients such as nitrogen and phosphorus causes the formation of a "dead zone" that spans as much as a third of the bay in the summertime.[67] The Chesapeake Bay watershed overlaps with some of the most intensive Marcellus Shale fracking activity, creating the potential for additional pollution that will make the bay's pollution reduction goals more difficult to meet.

A rapid expansion of shale gas drilling could contribute an additional 30,000 to 80,000 pounds per year of nitrogen and 15,000 to 40,000 pounds per year of phosphorus to the bay, depending on the amount of forest lost.[68] While this additional pollution represents a small fraction of the total pollution currently reaching the bay, it is pollution that would need to be offset by reductions elsewhere in order to ensure that the Chesapeake Bay meets pol-



Many waterways in the Marcellus Shale region drain into the Chesapeake Bay. The loss of forests to natural gas development could add to pollution levels in the bay, threatening the success of state and federal efforts to prevent the "dead zone" that affects the bay each summer. Sources: Skytruth, U.S. Energy Information Administration, Chesapeake Bay Program

Pronghorn antelope are among the species that have been affected by intense natural gas development in Wyoming. Credit: Christian Dionne

lution reduction targets designed to restore the bay to health.[69] Based on an estimate of the cost per pound of nitrogen reductions from a recent analysis of potential nutrient trading options in the Chesapeake Bay watershed,[70] the cost of reducing nitrogen pollution elsewhere to compensate for the increase from natural gas development would run to approximately $1.5 million to $4 million per year.

Habitat Loss and Fragmentation

Extensive natural gas development requires the construction of a vast infrastructure of roads, well pads and pipelines, often through remote and previously undisturbed wild lands. The disruption and fragmentation of natural habitat can put species at risk.

Hunting and other forms of outdoor recreation are economic mainstays in several states in which fracking is taking place. In Wyoming, for example, non-resident hunters and wildlife watchers pumped $340 million into the state's economy in 2006.[73] Fracking, however, is degrading the habitat of several species that are important attractions for hunters and wildlife viewers.[74]

A 2006 study found that the construction of well pads drove away female mule deer in the Pinedale Mesa area of Wyoming, which was opened to fracking in 2000, and that the deer stayed away from areas near well pads over time. The study suggested that natural gas development in the area was shifting mule deer from higher quality to lower quality habitat.[75] The mule deer population in the area dropped by 56 percent between 2001 and 2010 as fracking in the area continued and accelerated.[76]

Concerns have also been raised about the impact of natural gas development on pronghorn antelope. A study by the Wildlife Conservation Society documented an 82 percent reduction in high-quality pronghorn habitat in Wyoming's natural gas fields, which have historically been key wintering grounds.[77]

The Wyoming Game & Fish Department assigns "restitution values" for animals illegally killed in the state, with pronghorn valued at $3,000 per animal and mule deer at $4,000 per animal.[78] The decline of approximately 2,910 mule deer estimated to have occurred in the Pinedale Mesa between 2001 and 2010, using this valuation, would represent lost value of more than $11.6 million, although there is no way to determine the share of the decline attributable to natural gas development alone.[79]

"The decline of approximately 2,910 mule deer in the Pinedale Mesa, using this valuation, would represent lost value of more than $11.6 million."

The impact of fracking on wildlife-based recreation is, of course, only one of many ways in which harm to species translates into lasting economic damage. Wildlife provides many important ecosystem goods and services. (See next page.) Birds, for example, may keep insect and rodent populations in check, help to distribute seeds, and play other roles in

Loss of Ecosystem Services

Forests and other natural areas provide important services—they clean our air, purify our water, provide homes to wildlife, and supply scenic beauty and recreational opportunities. Many of these services would be costly to replicate—for example, as noted on page 14, the natural filtration provided by the forests of upstate New York has thus far enabled New York City to avoid the $6 billion expense of building a water filtration plant to purify the city's drinking water.

In recent years, economists have worked to quantify the value of the ecosystem services provided by various types of natural land. The annual value of ecosystem services provided by deciduous and evergreen forests, for example, has been estimated at $300 per acre per year.[71] Researchers with The Nature Conservancy and various Pennsylvania conservation groups have projected that 38,000 to 90,000 acres of Pennsylvania forest could be cleared for Marcellus shale development by 2030. The value of the ecosystem services provided by this area of forest, therefore, ranges from $11.4 million to $27 million per year.[72] Widespread land clearance for fracking jeopardizes the ability of the forest to continue to provide these valuable services.

Other natural features affected by fracking—including groundwater, rivers and streams, and agricultural land—provide similar natural services. The value of all of those services—and the risk that an ecosystem's ability to deliver them will be lost—must be considered when tallying the cost of fracking.

Oil and gas development fragments valuable natural habitat. Above, the Jonah gas field in Wyoming.
Credit: Bruce Gordon

the maintenance of healthy ecosystems. Adding these impacts to the impacts on hunters, anglers and wildlife-watchers magnifies the potential long-term costs of fracking from ecosystem damage.

Contribution to Global Warming

Global warming is the most profound challenge of our time, threatening the survival of key species, the health and welfare of human populations, and the quality of our air and water. Fracking produces pollution that contributes to the warming of the planet in greater quantities than conventional natural gas extraction.

"Emissions of methane during well completion from each uncontrolled fracking well impose approximately $139,000 in social costs related to global warming."

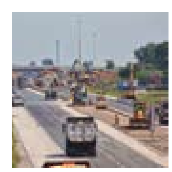
Fracking's primary impact on the climate is through the release of methane, which is a far more potent contributor to global warming than carbon dioxide. Over a 100-year timeframe, a pound of methane has 21 times the heat-trapping effect of a pound of carbon dioxide.[80] Methane is even more potent relative to carbon dioxide at shorter timescales.

Leaks during the extraction, transmission and distribution of natural gas release substantial amounts of methane to the atmosphere. Recent air monitoring near a natural gas field in Colorado led researchers at the National Oceanic and Atmospheric Administration and the University of Colorado, Boulder, to conclude that about 4 percent of the extracted gas was lost to the atmosphere, not counting the further losses that occur in transportation.[81]

Research by experts at Cornell University suggests that fracking is even worse for the climate than conventional gas production. Their study finds that methane leakage from fracking wells is at least 30 percent greater than, and perhaps double, leakage from conventional natural gas wells.[82]

Global warming threatens costly disruption to the environment, health and infrastructure. Economists have invested significant energy into attempting to quantify the "social cost" of emissions of global warming pollutants—that is, the negative impact on society per ton of emissions. A 2011 EPA study estimated the social cost of methane as lying within a range of $370 to $2,000 per ton. Each uncontrolled fracking well produces approximately 156 tons of methane emissions.[83] At a modest discount rate (3 percent) the social cost was $895 per ton in 2010.[84] Emissions of methane during well completion from a single uncontrolled fracking well, therefore, would impose $139,620 in social costs related to global warming.[85] This figure does not include emissions from other aspects of natural gas extraction, transmission and distribution, such as pipeline and compressor station leaks. Leakage from those sources further increases the impact of fracking on the climate—imposing impacts that may not be fully realized for decades or generations.

Impacts on Public Infrastructure and Services



Fracking imposes both immediate and long-term burdens on taxpayers through its heavy use of public infrastructure and heavy demand for public services.

Road Damage

Fracking requires the transportation of massive amounts of water, sand and fracking chemicals to and from well sites, damaging roads. In the northern tier of Pennsylvania,

Fracking requires millions of gallons of water and large quantities of sand and chemicals, all of which must be transported to well sites, inflicting damage on local roads. Above, a well site in Washington County, Pa. Credit: Robert Donnan

each fracking well requires approximately 400 truck trips for the transport of water and up to 25 rail cars' worth of sand.[86] The process of delivering water to a single fracking well causes as much damage to local roads as nearly 3.5 million car trips.[87]

"The state of Texas has convened a task force to review the impact of drilling activity on local roads and has approved $40 million in funding for road repairs in the Barnett Shale region."

Added up across dozens of well sites in a given area, these transportation demands are enough to lead to a noticeable increase in traffic—as well as strains on local roads. Between 2007 and 2010, for example, the amount of truck traffic on three major northern Pennsylvania highways increased by 125 percent, according to a regional transportation study. The study concluded that state and local governments will have to repave many roads every 7 to 8 years instead of every 15 years.[88]

The state of Texas has convened a task force to review the impact of drilling activity on local roads and has approved $40 million in funding for road repairs in the Barnett Shale region.[89] A 2010 Pennsylvania Department of Transportation document estimated that $265 million would be required for repair of roads affected by Marcellus Shale drilling.[90] Pennsylvania has negotiated bonding requirements with natural gas companies to cover the cost of repairs to local roads and some other states have done the same, but these requirements may not cover the full impact of fracking on roads, including impacts on major highways and the costs of traffic delays and vehicle repairs caused by congested or temporarily degraded roads.

Increased Demand for Water

The millions of gallons of water required for hydraulic fracturing come from aquifers, surface waterways, or water "recycled" from previous frack jobs.

In some areas, fracking makes up a significant share of overall water demand. In 2010, for example, fracking in the Barnett Shale region consumed an amount of water equivalent to 9 percent of the city of Dallas' annual water use.[91] An official at the Texas Water Development Board estimated that one county in the Eagle Ford Shale region will see the share of water consumption devoted to fracking and similar activities increase from zero a few years ago to 40 percent by 2020.[92] Unlike other uses, water used in fracking is lost to the water cycle forever, as it either remains in the well, is "recycled" (used in the fracking of new wells), or is disposed of in deep injection wells, where it is unavailable to recharge aquifers.

"Texas adopted a State Water Plan in 2012 that calls for $53 billion in investments in the state water system, including $400 million to address unmet needs in the mining sector (which includes hydraulic fracturing)."

Water withdrawals for fracking can harm local waterways (see page 20) and increase costs for agricultural and municipal water consumers (see page 31). They may also lead to calls for increased public investment in water infrastructure. Texas, for example, adopted a State Water Plan in 2012 that calls for $53 billion in investments in the state water system, including $400 million to address unmet needs in the mining sector (which includes hydraulic fracturing) by 2060.[93] Fracking is projected to account for 42 percent of water use in the Texas mining sector by 2020.[94]

Earthquakes

Fracking also has the potential to affect public infrastructure through induced earthquakes resulting from underground disposal of fracking wastewater. A recent report by the National Research Council identified eight cases in which seismic events were linked to wastewater disposal wells (not necessarily all for fracking wastes) in Ohio, Arkansas and Colorado.[95] In Ohio, which has become a popular location for the disposal of wastewater from Marcellus shale drilling, more than 500 million gallons of fracking wastewater were disposed of in underground wells in 2011.[96] That same year, the Youngstown, Ohio, area experienced a series of earthquakes, prompting Ohio officials to investigate potential links between the earthquakes and a nearby injection well. While the study did not determine a conclusive link between the injection well and the earthquakes, it did find that "[a] number of coincidental circumstances appear to make a compelling argument for the recent Youngstown-area seismic events to have been induced (by the injection well)."[97]

"The earthquakes raise concerns about the potential for damage to public infrastructure as well as private property."

The earthquakes that have occurred thus far have not caused significant damage, but they raise concerns about the potential for damage to public infrastructure (such as water and sewer lines) as well as private property.

Cleanup of Orphaned Wells

Gas and oil companies face a legal responsibility to plug wells properly when they cease to be productive and to "reclaim" well sites by restoring them to something approaching their original vegetated condition. The oil and gas industry, however, has a long track record of failing to clean up the messes it has made—leaving the public to pick up the tab.

Pennsylvania alone has more than 8,000 orphaned wells drilled over the last century and a half, and the Pennsylvania Department of Environmental Protection is unaware of the location or status of an additional 184,000 wells.[98]

Orphaned wells are not a problem of the past; newer wells can be orphaned by their operators, too, and left to taxpayers to clean up. Nearly 12,000 coal-bed methane wells in Wyoming were idle as of 2011, neither producing nor plugged.[99] Wyoming officials are concerned that several companies that operate coal-bed methane wells may file for bankruptcy if natural gas prices do not rebound or if the companies cannot sell off some assets to raise capital to comply with state environmental protections. If that were to happen, the state could be forced to plug and remediate the idled wells.

"A 2011 study of a Marcellus Shale well by researchers with the University of Pittsburgh estimated the cost of site reclamation (including reclamation of retention ponds and repairs to public roads) at $500,000 to $800,000 per well site."

Another way in which the public may face exposure to costs is when a well plug fails, requiring attention years later. Chemical, mechanical or thermal stress can cause the cement to

Volunteer firefighters respond to a fire in a wastewater pit at an Atlas Energy Resources well site in Washington County, Pa., in March 2010. Fracking places increased demands on emergency responders, creating new dangers that require additional training, and increasing demands for response to traffic accidents involving heavy trucks. Credit: Robert Donnan crack or loosen and allow contamination from saline aquifers or gas-bearing layers to reach freshwater aquifers. The risk of plug failure increases over time.[100] In some states, such as Pennsylvania, plugging and reclamation bonds are released one year after a well is plugged, leaving the state with no way to hold drillers accountable for the cost of plugging wells that fail later.

The Pennsylvania Department of Environmental Protection estimates that plugging a 3,000 foot-deep oil or gas well and reclaiming the drill site costs an average of $60,000.[101] However, some well reclamation costs have exceeded $100,000.[102] And Cabot Oil & Gas Corporation claims to have spent $730,000 per well to cap three shale gas wells in Pennsylvania.[103] A 2011 study of a Marcellus Shale well by researchers with the University of Pittsburgh estimated the cost of site reclamation (including reclamation of retention ponds and repairs to public roads) at $500,000 to $800,000 per well site.[104]

While estimates of the costs of plugging and remediation of fracked wells vary, those costs almost always exceed a state's bonding requirements. Pennsylvania's recently revised bonding requirements, for example, require drillers to post maximum bonds of only $4,000 per well for wells less than 6,000 feet in depth and $10,000 per well for wells deeper than 6,000 feet, creating the potential for the public to be saddled with tens or hundreds of thousands of dollars in liability for plugging and reclamation of abandoned wells whose owners have gone bankrupt or walked away from their responsibilities.[105] The experience of previous resource extraction booms and busts suggests that the full bill for cleaning up orphaned wells may not come due for decades.

In parts of the country, fracking takes place in close proximity to homes, schools and hospitals, creating the potential for conflict. A Texas study has found that some homes near fracking well sites have lost value. Above, a natural gas flare near homes in Hickory, Pa. Credit: Robert Donnan

Emergency Response Needs

Increasing traffic—especially heavy truck traffic—has contributed to an increase in traffic accidents and fatalities in some areas in which fracking has unleashed a drilling boom, as well as an increase in demands for emergency response. In the Bakken Shale oil region of North Dakota for example, the number of highway crashes increased by 68 percent between 2006 and 2010, with the share of crashes involving heavy trucks also increasing over that period. The estimated cost of those crashes increased by $31 million.[106]

"A 2011 survey in eight Pennsylvania counties found that 911 calls had increased in seven of them, with the number of calls increasing in one county by 49 percent over three years, largely due to an increase in incidents involving heavy trucks."

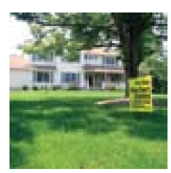
The need to address traffic accidents is one driver of increased need for emergency response in communities experiencing fracking. A 2011 survey by StateImpact Pennsylvania in eight counties found that 911 calls had increased in seven of them, with the number of calls increasing in one county by 49 percent over three years, largely due to an increase in incidents involving heavy trucks.[107]

Social Dislocation and Social Service Costs

The influx of temporary workers that often accompanies fracking also puts a squeeze on housing supplies, creating social dislocation that, in some cases, creates new demand for government social services. Rental prices have doubled or tripled in communities experiencing a boom in Marcellus Shale drilling.[108] Overheated local housing markets have driven lower income renters into substandard housing or homelessness. Elderly residents have faced a shortage of subsidized housing.[109] Requests for assistance from social service agencies have increased.[110] In Bradford County, Pa., the local children and youth services agency increased its spending on housing subsidies by 50 percent or $10,000 per year.[111] In the same county, a government agency purchased and distributed tents for use as temporary housing.[112] In Greene County, in southwestern Pennsylvania, the documented number of homeless jumped from zero to 40 in a single year.[113] Children of families that lose permanent housing may be at risk of being separated from their families and placed into foster care. A 2010 survey of Pennsylvania local governments in municipalities experiencing Marcellus Shale drilling activity found that more governments reported an increase in municipal expenditures since the onset of fracking than reported an increase in revenues.[114]

"In Greene County, in southwestern Pennsylvania, the documented number of homeless jumped from zero to 40 in a single year."

Broader Economic Impacts



Fracking imposes damage on the environment, public health and public infrastructure, with significant economic costs. But poorly thought-out resource extraction also has a legacy of undercutting the long-term economic prospects of the very "boomtowns" it creates.

A 2008 study by the firm Headwaters

Economics found that Western counties that have relied on fossil fuel extraction are doing worse economically compared with peer communities and are less well-prepared for growth in the future, due to a less-diversified economy, a less-educated workforce, and greater disparities in income.[115]

In addition, fracking can undermine local economies in many ways, including through its impacts on housing and agriculture.

Value of Residents' Homes at Risk

Fracking can reduce the value of nearby properties as a result of both actual pollution and the stigma that may come from proximity to industrial operations and the potential for future impacts. A 2010 study in Texas concluded that homes valued at more than $250,000 and within 1,000 feet of a well site saw their values decrease by 3 to 14 percent—there was no discernible impact on property values beyond that distance or for lower-priced houses.[116] A 2001 study of property values in La Plata County, Colorado, found that properties with a coalbed methane well had seen their sales value decrease by 22 percent.[117] Even where impacts on sales values are difficult to establish, chronic conditions caused by fracking—such as odor, traffic, noise, concerns about pollution of the air and water, earthquake concerns and visual impacts—may adversely affect residents' use and enjoyment of their homes.

"A 2010 study in Texas concluded that homes valued at more than $250,000 and within 1,000 feet of a well site saw their values decrease by 3 to 14 percent."

Properties on and near locations where fracking is taking place may also be more difficult to finance and insure, potentially affecting their value. Mortgage lenders and insurers have recently taken steps to protect themselves from fracking-related risks. Several mortgage lenders have begun to require extensive buffer zones around homes on land with gas leases before issuing a new mortgage or to refuse to issue new mortgages on land with natural gas leases.[118] For example, Brian and Amy Smith live across the street from a gas drilling site in Daisytown, Pa. In the spring of 2012, Quicken Loans denied their mortgage application, stating that "Unfortunately, we are unable to move forward with this loan. It is located across the street from a gas drilling site." The Smiths were also rejected by two other national lenders.[125]

In addition, in July 2012, Nationwide Insurance issued a statement clarifying that its policies do not cover damages related to fracking, noting that "the exposures presented by hydraulic fracturing are too great to ignore."[119] Nationwide's announcement drew attention to the fact that standard homeowners' insurance policies do not cover damage related to fracking.

Farms in Jeopardy

Fracking largely takes place in rural areas. Several aspects of fracking have the potential to harm farmers.

Direct exposure to fracking wastewater can harm livestock. Researchers at Cornell University have identified multiple instances of harm to animals associated with natural gas operations in Colorado, Louisiana, New York, Ohio, Pennsylvania and Texas. In one case examined by the researchers, 140 cows were exposed when the liner of a wastewater impoundment was slit, enabling wastewater to flow onto a pasture and into a pond the cattle used as a water supply. Of those 140 cows, approximately 70 died. Assuming an average cost per cow of $1,600[120], the loss of

"The loss of 70 cows from a single incident would have an impact of at least $112,000."

70 cows from a single incident would have an impact of at least $112,000. In addition to this direct replacement cost, exposure of livestock to contaminants from fracking is likely to cost farmers in other ways, for example, by impeding the ability of animals to reproduce or reducing the ability of a farmer to market his or her livestock.

Researchers at Penn State University have identified a link between increased drilling activity in the Marcellus Shale and decreased production at dairy farms in counties where drilling is taking place. The five counties in which drilling activity was the heaviest experienced an 18.5 percent reduction in milk production between 2007 and 2010.[121] The researchers did not reach a conclusion as to the cause of the decline. But another review of the community implications of fracking suggested that rising transportation costs caused by workforce competition with gas drilling has added a new economic challenge for dairy farmers.[122] The demise of farming in a community threatens to also bring down stores and industries that were built to support farmers, eroding a community's economic base.

In arid western states, some farmers face higher costs for water as a result of competing demands from fracking. A 2012 auction of unallocated water conducted by the Northern Water Conservation District saw natural gas industry firms submit high bids, with the average price of water sold in the auction increasing from $22 per acre-foot in 2010 to $28 per acre-foot in the first part of 2012.[123] For the 25,000 acre-feet of water auctioned, this would amount to an added cost of $700,000.

Finally, farmers engaged in organic agriculture have raised concerns that fracking could make it more difficult for them to sell their products to health-conscious consumers. One New York City food co-op, for example, has already stated that they may stop purchasing agricultural products from New York state farms in areas where fracking takes place.[124]

Fracking poses threats to farming, both directly through the potential loss of livestock due to exposure to toxic contaminants, and indirectly by increasing farmers' costs of doing business during the "boom" portion of the boom-bust cycle of development. Here, cows graze in Erie, Colorado, which has experienced fracking activity. Credit: Jill/Blue Moonbeam Studio.

Who Pays the Costs of Fracking?

The oil and gas industry is unlikely ever to be held accountable for many of the costs of fracking documented in this report—at least under current law.

Time and again in the history of the oil and gas industry, legal safeguards have proven inadequate to protect the environment and communities from exposure to long-term costs. The public can be exposed to many different and significant costs from fracking for several reasons:

- **Inadequate financial assurance.** The boom-bust cycle typical of the oil and gas industry means that many firms (or their subcontractors) may be unable or unwilling to fulfill their financial obligations to properly plug wells, reclaim land, remediate environmental problems, and compensate those harmed by their activities. State bonding requirements are intended to protect the public by ensuring that financial resources exist to cover the cost of well plugging and reclamation, but the amounts of those bonds are generally too low to pay for proper well closure, and state laws generally do not require drillers to obtain bonds to cover the cost of off-site environmental remediation or compensation to victims.

- **Delayed appearance of harm.** Some damages from fracking are apparent right away—for example, the appearance of tainted well water immediately after fracking of a nearby well. But other damages—especially ecosystem and health damages—may not appear for years or even decades, making it likely that the individuals and companies responsible will be long gone from the scene by the time the scope of the damage becomes apparent. This is particularly worrisome given concerns about the potential long-term impact of fracking and wastewater disposal on precious groundwater supplies.

- **Diffuse, regional impacts.** Some impacts of fracking only appear when many wells are drilled in a concentrated geographic area. For example, the erosion caused by clearance of a single well pad may not be enough to harm wildlife in a local stream, but the clearance of land for dozens of wells in the same area may have a harmful cumulative impact. In these cases, assigning legal responsibility for the damage to any single well may prove difficult or impossible.

- **Inability to access legal remedies.** Those who are harmed by fracking can face an uphill battle in the legal system. Litigation is frequently a lengthy, expensive, time-consuming and difficult road for citizens to pursue in seeking to resolve claims of damage from environmental conditions. This is particularly true with regard to health impacts. It is extraordinarily difficult, for example, to meet the legal standards of proof that an individual's illness was caused by exposure to a particular toxic chemical at a particular time. Even where property damage is concerned, such litigation typically requires expert analysis and testimony to prove causation and diminished value of the affected property.

As a result, many of the costs of fracking are often borne not by the companies that benefit, but by nearby residents, taxpayers, those whose enjoyment of clean air, clean water and abundant wildlife is impacted by fracking, and even by future generations.

Infographic design: Jenna Leschuk

Accounting for the True Costs of Fracking: Conclusion and Recommendations

Fracking harms the environment, public health and our communities in many ways.

If fracking is to continue, the minimum that citizens should expect is the enforcement of tough rules to reduce fracking damage and up-front financial assurances that guarantee that the oil and gas industry cleans up the damage it does cause and compensates any victims. Current laws, however, are inadequate to ensure that even this basic standard of protection is met. Failing to hold the oil and gas industry accountable not only leaves the public exposed to many types of costs, but it also creates a disincentive for the industry to take action to prevent accidents and environmental contamination.

Federal, state and local governments should **hold the oil and gas industry accountable for the costs of fracking** using a variety of financial tools, including:

- **Bonding** – Oil and gas companies should be required to post bonds (or other forms of financial assurance) sufficient to plug wells and reclaim well sites, pay for road repairs and other physical damage caused by fracking, remediate environmental contamination, fully compensate anyone harmed by activities at well sites, and address other costs imposed by fracking. Requiring drilling companies to post bonds for these expenses ensures that the oil and gas industry will be able to take care of its responsibilities to the public and the environment even amid the "boom-bust" cycles typical of the oil and gas industry.

- **Fees, taxes and other charges** – Bonding may not be the best solution for recouping every cost imposed by fracking. For example, natural gas companies could not be required to take out bonds to cover expenses related to a single well's contribution to global warming—the effect of which might be felt half a world away. While strong regulation should be used to limit the broader environmental, public health and community impacts of fracking, fees and other charges can also recoup for the public some of the costs imposed by fracking and create an economic incentive for the oil and gas industry to reduce its impact.

The mounting evidence of fracking's impact on our environment, health and communities is enough to spur reconsideration of when and under what circumstances it is permitted to take place. If fracking is permitted to continue, Americans deserve to know that the oil and gas industry—not the public at large—will pick up the tab.

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Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

Background Supplemental Technical Support Document for the Final New Source Performance Standards

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Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

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Contents

SUPPLEMENTAL TECHNICAL SUPPORT DOCUMENT SUMMARY

This Supplemental Technical Support Document (TSD) provides background and technical analyses to support the final New Source Performance Standards (NSPS) for limiting volatile organic compound (VOC) and sulfur dioxide (SO_2) emissions from the Oil and Natural Gas Sector. The standards were developed according to section 111(b)(1)(B) under the Clean Air Act, which requires EPA to review and revise, if appropriate, NSPS standards. The final standards were developed following consideration of public comments received on the standards proposed on August 23, 2011 (76 FR 52738). Section 1.0 presents the development of the emission factor for hydraulically fractured gas well completions and recompletions used in the NSPS regulatory impacts analysis, including a discussion of the methodology and the data sources. This section also provides an analysis of relevant data submitted with the public comments. Section 2.0 presents the derivation of an equation to determine the pressure threshold for a "low pressure" well. In Section 3.0, changes to the gas well refracture frequency estimates from the proposed NSPS to the final standards are summarized. Section 4.0 presents the impacts of regulating VOC emissions from new gas well completions following hydraulic fracturing where reduced emissions completions (RECs) are required. Section 5.0 details the analysis used to estimate the number of gas well completions with hydraulic fracturing voluntarily performed with capture and combustion equipment in the year 2015. Section 6.0 presents an estimate of the impacts related to the regulation of centrifugal compressors and the data used in those estimates. Section 7.0 presents an analysis of impacts associated with regulatory options for storage vessels. Finally, Section 8.0 provides the results of the equipment leak cost analysis for the NSPS using emission factors and cost data from the Uniform Standards for Equipment Leaks rule (40 CFR part 65, subpart J) that EPA proposed on February 24, 2012. Appendices contained at the end of this TSD provide supplemental information to the main chapters described above.

The following table presents a crosswalk between the sections of the proposal TSD and the sections of this document that update the proposal TSD sections.

Proposal TSD		Updated by Section in this Document
Section Number	Section Title	
1.0	New Source Performance Background	N/A
2.0	Sector Description	N/A
3.0	New Source Performance Review Process	N/A
4.0	Well Completions and Recompletions	1.0, 2.0, 3.0, 4.0, 5.0
5.0	Pneumatic Controllers	N/A
6.0	Compressors	6.0
7.0	Storage Vessels	7.0
8.0	Equipment Leaks	8.0

1.0 EVALUTION OF THE EMISSION FACTOR FOR HYDRAULICALY FRACTURED GAS WELL COMPLETIONS AND RECOMPLETIONS

This section details the development of the emission factor used in the NSPS regulation impacts analysis, including a discussion of the methodology and the data sources, and then provides detail on the analysis of data presented to EPA through the public comment period of the NSPS.

1.1 Emission Factor Development

1.1.1 Previous Estimates of Methane from Natural Gas Production

EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks[1] methane emissions estimates for natural gas systems depend heavily on emissions factors from a 1996 EPA/GRI study.[2] Hydraulically fractured gas well completions and workovers are a significant proportion of completions and workovers today, but were not as common during the development of the 1996 EPA/GRI study. The study calculated an emission factor for gas well completions by making several key assumptions. These assumptions were based on the data and knowledge of industry practices available at the time but which are not appropriate for hydraulically fractured wells. These assumptions included:

- Emissions that occur during the well completion are equal to one day of the average gas production rate per gas well in 1992 based on the American Gas Association's *Gas Facts.*
- All completion emissions are flared (reducing the methane emissions from each completion by approximately 98 percent).

Since the publication of the 1996 EPA/GRI study, the number of hydraulically fractured gas well completions has increased significantly to 9,000 hydraulically fractured wells completed annually according to the National Energy Modeling System's (NEMS) models. Through extensive interactions with oil and gas companies and industry experts and through a review of best available data, EPA became aware that the assumptions made in the 1996 EPA/GRI study did not accurately characterize methane emissions from hydraulically fractured gas wells. In particular:

- The 16.97 million cubic feet per year average gas production rate in 1992, which GRI used as a surrogate for the average completion flow rate, includes a large number of marginal wells. Marginal low pressure wells have significantly less gas production than newly completed hydraulically fractured wells.
- Significant quantities of gas are produced during the completion process for a hydraulically fractured gas well, in particular during the flowback period. In 2004, companies began sharing information with EPA on voluntary activities to reduce emissions from hydraulically fractured gas well completions, referred to as Reduced Emission Completions. Companies reported that the extended flowback time (as compared to conventional completions) and increased volume of natural gas during the

[1] http://epa.gov/climatechange/emissions/usinventoryreport.html
[2] EPA/GRI. Methane Emissions from the Natural Gas Industry. June 1996. Available at http://www.epa.gov/gasstar/tools/related.html

flowback period, made it cost-effective to bring portable equipment on-site to capture the increased natural gas for market. EPA currently assumes an average flowback period of 3 to 10 days for hydraulically fractured wells.

- Finally, through interactions with companies at EPA and industry events as well as public data and experiences shared by the industry, EPA is aware that not all companies are flaring the flowback gas, contrary to the assumption in the 1996 EPA/GRI study. In fact, many companies are either capturing through reduced emissions completions (RECs) or venting the gas that occurs during the completion of hydraulically fractured gas wells.

Based on this information, and review of available data on emissions per completions from hydraulic fracturing, EPA has concluded that the emission factor for gas well completions from the 1996 EPA/GRI study no longer represents the diversity of gas well completion practices in use today, and the emission rates associated with these practices. On the basis of the available data reported by companies carrying out hydraulic fracturing and RECs, EPA developed an emission factor specifically for gas well completions with hydraulic fracturing, as described in the section below.

1.1.2 Emission factor for completions with hydraulic fracturing

In 2010, on the basis of information reported by companies carrying out hydraulic fracturing and RECs, EPA developed an emission factor specifically for hydraulically fractured gas well completions. This factor was first used in the Technical Support Document for Subpart W of Part 98, GHG reporting rule, and also in the 1990-2009 Inventory (published in April 2011).

The emission factor for gas well completions with hydraulic fracturing was developed using four data sources, together representing data from over 1,000 well completions with hydraulic fracturing. These data were provided to EPA or its technical contractors by industry for presentation at Natural Gas STAR technology transfer workshops from 2004-2007. For each data source, EPA calculated the average gas release per gas well completion. The data from these wells collectively indicate that the true average gas release rate for a hydraulically fractured well completion is substantially higher (greater than two orders of magnitude) than the 1996 GRI/EPA emission factor that is applicable to conventional well completions. These data also indicate that there is a high degree of variability in gas release rates across hydraulically fractured well completions due to geology, technology and operating conditions. The four calculated averages were each then rounded to the nearest single significant digit to reflect the precision of these averages. The resulting emission factors from each of the four data sources were arithmetically averaged to determine the final emission factor for gas well completions with hydraulic fracturing.

As the variability was already reflected through the rounding of the rate developed from each data set, EPA elected not to round the final average calculated from the four rates. Had EPA rounded the final number, it would be 9,000 Mcf per completion or 2% lower. If EPA had not rounded the results of the initial studies, the final average well emission factor would be 11,057 Mcf per completion, or 21% higher.

A detailed breakdown of each source and the calculation method to determine the emission factor is shown in Table 1-1. The calculation is as follows:

$$\frac{\left(6{,}000\frac{Mcf}{completion}\right)\left(10{,}000\frac{Mcf}{completion}\right)\left(700\frac{Mcf}{completion}\right)\left(20{,}000\frac{Mcf}{completion}\right)}{4} = 9{,}175\frac{Mcf}{completion}$$

Table 1-1: Summary of Data Sources Used for the Original EF (9,175 Mcf per completion)

Data Source	Year(s)	# of Wells	Total Gas Emissions (Mcf)	Average Gas Emissions Per Completion (Mcf)	Formation Type
Industry Data Set #1	-	106	616,887	5,820	Tight Sands
Williams	2002 to 2006	1,064	26,014,000	24,449	Tight Sands
Devon	2004	30	357,000	11,900	Shale
Weatherford	2004	3	2,000	667	CBM

1.1.2.1 Industry Data Set #1

In 2004, an EPA technical contractor received a data set from a natural gas production company. The data set included information on volumes of gas sold and flared from 106 completions at wells with hydraulic fracturing (see Appendix A). On the basis of this information, the contractor calculated a national-level estimate of recoverable gas from completions[3]. In the original work to develop the factor, EPA used the national estimate of recoverable gas from completions and information on national well counts to calculate average potential emissions per well.[4] The calculated results of average value of potential emissions per well, 5,815 Mcf per completion, was rounded to the nearest 1,000 Mcf per completion (one significant figure), equaling **6,000 Mcf per completion.**

The gas producer has since provided EPA with the detailed data set, after removing identifying information such as the geographic area and company name. EPA used this data set on number of completions, gas flared, and sold for each completion to calculate average potential emissions

[3] Green Completions. Natural Gas STAR Producer's Technology Transfer Workshop. September 21, 2004. <http://epa.gov/gasstar/workshops/techtransfer/2004/houston-02.html> Slide 4.
[4] Appendix B of the *Background Technical Support Document* for Subpart W of the *Greenhouse Gas Reporting Rule, available at http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf*

(5,820 Mcf per completion, which also rounds to 6,000 Mcf per completion). The detailed data set is shown in Appendix A.

1.1.2.2 Williams Data

Williams Inc. reported generating 26,014 MMcf of natural gas from 1,064 completions[5]. Therefore,

[26,014 MMcf]*[1000 Mcf/MMcf] / [1064 completions] = 24,449 Mcf per completion

The 24,449 Mcf per completion was rounded to the nearest 10,000 Mcf per completion, equaling **20,000 Mcf per completion.**

1.1.2.3 Devon Data

Devon Energy provided EPA[6] with data from 30 wells with an average rate of 11,900 Mcf natural gas recovered and sold rather than vented. To calculate a potential emissions rate from this data, EPA assumed that 90% of the natural gas vented was recovered. Therefore,

[11,900 Mcf/completion] / [90%] = 13,222 Mcf per completion

The 13,222 Mcf per completion was rounded to the nearest 10,000 Mcf per completion, equaling **10,000 Mcf per completion.**

1.1.2.4 Weatherford Data

Weatherford provided data from 3 well completions[7]. Those completions together captured 2 MMcf of gas. Again to calculate a potential emissions factor, EPA assumed that 90% of the natural gas released was recovered. Therefore,

[2 MMcf/completion]*[1000 Mcf/MMcf] / ([90%]*[3 completions]) = 740 Mcf per completion

The 740 Mcf per completion was rounded to the nearest 100 Mcf per completion, equaling **700 Mcf per completion.**

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[6] Green Completions. Natural Gas STAR Producer's Technology Transfer Workshop. September 21, 2004. <http://epa.gov/gasstar/workshops/techtransfer/2004/houston-02.html> Slide 13.
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1.1.3 Estimating Emissions from Completions with Hydraulic Fracturing

The 9,175 Mcf per completion emission factor represents natural gas released from the completion of a hydraulically fractured natural gas well (i.e., potential gas emissions from the completion process in the absence of controls to capture or flare the released gas). It is very important to note that in calculating total national emissions from completions with hydraulic fracturing for the Inventory of U.S. Greenhouse Gas Emissions and Sinks, the EPA adjusts calculated methane release for methane that is actually not emitted (i.e., that is instead flared or controlled with certain technologies and practices) due to both voluntary action and State regulations. EPA uses this approach across the national inventory for many source categories, and it is consistent with internationally agreed guidance from the IPCC.[8] Specifically, the development of the national emissions estimates for unconventional natural gas wells requiring hydraulic fracture involves the following key steps:

- Start with the unmitigated national emission factor (9,175 Mcf of gas per completion).
- Adjust this factor by the average methane content of gas (on a regional basis).
- Multiply by the number of well completions and recompletions that involve hydraulic fracturing in each region, and then sum the regional totals to calculate total unmitigated methane emissions from the completions and workovers with hydraulic fracturing in the U.S.
- Calculate the amount of the methane that is not emitted, using data on voluntary action and State regulations in order to develop a more accurate picture of actual emissions from this source category and sector.
- Deduct the calculated amount of methane that is not emitted from the calculated total unmitigated methane emissions value to develop the net emissions estimate that is included in national emissions totals. The EPA notes that there has been a great deal of confusion about the Inventory methods for calculating net emissions. In the 1990-2010 Inventory of U.S. Greenhouse Gas Emissions and Sinks (public review draft), EPA has provided improved information on this methodology.

The NSPS analysis takes a similar approach in the development of its baseline emissions estimates, taking into account reductions from voluntary action and state regulations. Please see the RIA for more information on baseline emissions estimates.

[8] IPCC 2006, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Prepared by the National Greenhouse Gas Inventories Programme, Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds). Published: IGES, Japan.

1.2 Data Submitted Through NSPS Comments

This section describes well completions emissions information received through the NSPS public comments. Table 1-2 summarizes this information.

Table 1-2: Summary of Data Presented to EPA through NSPS Comment Period

Data Source	Year(s)	# of Wells	Total Gas Emissions (Mcf)	Average Gas Emissions Per Completion (Mcf)	Formation Type
Noble Energy	Unknown	5	16,800	3,360	Tight Sands
ConocoPhillips	2010	101	1,276,290	12,637	Tight Sands, Shale, CBM
URS Data	2011	98	71,948	734	Tight Sands, Shale
BP 1	2007	50	30,000	600	CBM
BP 2	2007	18	16,938	941	CBM
La Plata CEAP	Unknown	Unknown	Unknown	1,875	CBM
Southern Ute Tribe	Unknown	Unknown	Unknown	5,000	CBM

1.2.1 Noble Energy Data

In a comment submitted by Noble Energy for the NSPS[9], Noble provided average emissions per completion for 2 vertical and 3 horizontal wells. These wells were hydraulically fractured and produced from tight formations. The average from all 5 wells was 3,360 Mcf per completion. The emissions estimates were determined using a calibrated roots meter.

1.2.2 ConocoPhillips Data

In a comment submitted by Earthworks[10], Earthworks provided a reference to a presentation given by ConocoPhillips for a Natural Gas STAR Workshop in 2009. The presentation includes 101 wells in three different formation types. The average from all wells is 12,637 Mcf per completion.

[9] http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4228
[10] http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4275

1.2.3 URS Data

A comment submitted by Devon Energy[11] contains a study conducted by URS for ANGA. In the study, 7 companies submitted information relating to hydraulically fractured well completions at nearly 1200 wells. Of the 7 companies, 4 submitted emissions estimates for 98 well non-green completions (i.e., completions without RECs). Emissions estimates were not included for wells with RECs, which comprised 92% of the URS data set. For each of the 98 wells without REC completions, URS provided information on pressure, flowback duration, and choke size and used Equation W-11B from Subpart W of EPA's Greenhouse Gas Reporting Rule to calculate the emissions from completions. Using this equation, and a number of simplifying assumptions, URS calculated an average emissions rate of 765 Mcf per completion.

The 765 Mcf per completion is an emissions average per completion for wells in each of 5 basins. The 765 Mcf per completion factor represents the simple average of the average emissions calculated from the 5 basins. For the calculations shown below, we have recalculated the rate per completion so that it is not weighted by basin, as the other data sets evaluated do not allow for separate estimates by basin. Instead, using the data from the 98 wells with emissions estimates, EPA calculated the average emissions rate of the data set to be 734 Mcf per completion.

In reviewing the data and URS' use of the Subpart W equation, it became apparent that the resulting flowrate from Equation W-11B was misinterpreted to result in a flow rate at standard conditions when it was in fact a flowrate at actual conditions. Converting from actual volume (actual conditions) to standard volume (standard conditions), which is the input intended to estimate emissions from gas well venting during completions and workovers following hydraulic fracturing in Equation W-10A, EPA re-calculated an average value greater than 50,000 Mcf per completion. This value is far higher than the value presented by URS (765 Mcf per completion) and values given in other data sets. EPA's evaluation shows that the URS study is significantly underestimating emissions by using the equation at actual conditions, however, due to highly conservative assumptions made by URS (e.g., 100% gas in flowback instead of a mixture of gas and fluids, and maximum choke size and casing pressure), the recalculated emissions average of over 50,000 Mcf per completion may also be an inaccurate depiction of emissions. Given this uncertainty, EPA performed the analyses presented below both with (using the URS-calculated values per completion, averaged to 734 Mcf as noted above) and without the URS emissions estimates, for completeness and transparency.

1.2.4 BP

In a comment submitted by Earthworks9, the commenter referenced two BP presentations. The two data sets corresponded to well completions carried out in CBM formations. The first BP data set contained 50 well completions and had average emissions of 600 Mcf per completion. The second BP data set contained 18 well completions and had average emissions of 941 Mcf per completion.

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[11] http://www.epa.gov/quality/informationguidelines/documents/12003-attB.pdf

1.2.5 La Plata CEAP

In a comment submitted by Earthworks9, the commenter referenced a La Plata Climate and Energy Action Plan process in which two companies (BP and Red Cedar, the Southern Ute Indian Tribe's gas company) estimated that green completions could recover 1,875 Mcf per completion in the San Juan Basin based on industry completion data.

1.2.6 Southern Ute Tribe

In a comment submitted by Earthworks9, the commenter referenced a figure from a Programmatic Environmental Assessment (PEA) for 80-acre Infill Oil & Gas Development on the Southern Ute Indian Reservation developed by Environ. The emissions estimate was 5,000 Mcf per completion.

1.3 Evaluation of Alternative Emission Factor Calculations

In this section, EPA presents an analysis to determine whether or not the new information submitted through NSPS comments indicates a need to revise the emission factor used in the proposal, and to present and evaluate alternative emission factors.

To determine how the factor might change by including data received through the public comment period, EPA used the data submitted through NSPS comments (Table 1-2 above) in combination with the data used for the original emission factor calculation (Table 1-1 above) to calculate a number of alternative emission factors for consideration.

First, EPA developed two simple averages of the data: alternative factor 1, which is an average by well completion, and alternative factor 2, which is an average by data source.

The data used to calculate alternative factors 1, and 2, which includes the data used in the original emission factor and the data submitted through NSPS comments is presented in Table 1-3.

Table 1-3: Data Used for Alternative Factors 1 and 2

Data Source	Year(s)	# of Wells	Total Gas Emissions (Mcf)	Average Gas Emissions Per Completion (Mcf)	Formation Type
Industry Data Set #1*	Unknown	106	616,887	5,820	Tight Sands
Williams*	2002 to 2006	1,064	26,014,000	24,449	Tight Sands
Noble Energy	Unknown	5	16,800	3,360	Tight Sands

ConocoPhillips	2010	101	1,276,290	12,637	Tight Sands, Shale, CBM
URS Data	2011	98	71,948	734	Tight Sands, Shale
Devon*	2004	30	357,000	11,900	Shale
Weatherford*	2004	3	2,000	667	CBM
BP 1	2007	50	30,000	600	CBM
BP 2	2007	18	16,938	941	CBM
La Plata CEAP	Unknown	Unknown	Unknown	1,875	CBM
Southern Ute Tribe	Unknown	Unknown	Unknown	5,000	CBM

* Denotes sources used for the original emission factor calculation.

1.3.1 Alternative Factor 1: Average by Well Completion

The first alternative emission factor assessed was calculated by summing the total emissions from all data sets and dividing by the total number of completions. The La Plata CEAP and Southern Ute Tribe data points cannot be included when calculating emission factors using this method because these sources did not provide total emissions and total number of well completions. The resulting emission factor was about **20,574 Mcf per completion**. Including the URS data, the calculated value is 19,256 Mcf per completion.

This method results in an emission factor heavily affected by the number of well completions included in a given data set resulting in bias for one formation type. Tight sands are over represented, as 86% of the well completions in the data set were in tight sands, while nationally 26.5 percent of annual completions are tight sands (NEMS 2010). Further, one data source (Williams) accounts for 1,064 of the 1,377 well completions, which may bias the result towards the Williams data, which has an average emissions rate of 24,449 Mcf per completion.

1.3.2 Alternative Factor 2: Average by Data Source

The second alternative emission factor for assessment was estimated by performing a simple unweighted average of the average emissions per completion reported for each data source. This method calculated an average emission factor for each data source individually and then calculated a simple average of the 10 resulting emission factors. The average emission factors ranged from 600 Mcf per completion to 24,449 Mcf per completion. Of the 10 data sources, 3 corresponded to tight sands, 1 to shale, 5 to CBM, and 1 was a mix of all three formations. The resulting emission factor was about **6,725 Mcf per completion**. Including the URS data, the calculated factor is 6,180 Mcf per completion.

This method has the advantage of having no over-representation due to number of well completions included in a given data set resulting in bias for one formation type. However, it does result in over-representation of CBM completions due to the number of data sets including those types of completions (6 out of 10 data sources). In the U.S., 26.9 percent of annual completions are CBM (NEMS 2010). It also results in underrepresentation of shale completions, as only 2 of the data sources included shale completions. In the U.S. 46.5% of annual well completions are in shale (NEMS 2010).

1.3.3 Alternative Factors 3 through 5

Next, a number of alternatives that weigh the factor by formation type were developed. Based on the data EPA has evaluated, formation type can greatly influence the volume of gas released per completion. Based on observations of the available data from the U.S. oil and natural gas industry, of the three formation types included here, coal bed methane typically has the lowest volume of gas released per completion, and shale typically has the highest. As the national average gas release per completion will therefore be influenced by the mix of completions nationally, here we examine factors that take this mix into account. To develop these weighted factors, we disaggregated data sets that included more than one formation type. The Conoco Phillips data set included three formation types, and was split into three data sets, and the URS data included two formation types and was likewise split into two data sets. Table 1-5 presents this disaggregation.

Table 1-5: Data Used for Alternative Factors 3, 4, and 5

Data Source	Year(s)	# of Wells	Total Gas Emissions (Mcf)	Average Gas Emissions Per Completion (Mcf)	Formation Type
Industry Data Set #1*	Unknown	106	616,887	5,820	Tight Sands
Williams*	2002 to 2006	1,064	26,014,000	24,449	Tight Sands
Noble Energy	Unknown	5	16,800	3,360	Tight Sands
ConocoPhillips	2010	10	60,222	6,022	Tight Sands
URS Data	2011	41	16282	397	Tight Sands
ConocoPhillips	2010	83	1,200,000	14,458	Shale

Devon*	2004	30	357,000	11,900	Shale
URS Data	2011	57	55,666	977	Shale
Weatherford*	2004	3	2,000	667	CBM
BP 1	2007	50	30,000	600	CBM
BP 2	2007	18	16,938	941	CBM
La Plata CEAP	Unknown	Unknown	Unknown	1,875	CBM
Southern Ute Tribe	Unknown	Unknown	Unknown	5,000	CBM
ConocoPhillips	2010	8	16,068	2,009	CBM

* Denotes sources used for the original emission factor calculation.

1.3.3.1 Alternative Factor 3: Weighting by 3 Formation Types Based on Production

Using all of the data for which we had information on formation type, an emission factor for tight sands (9,913 Mcf per completion), an emission factor for shale (13,179 Mcf per completion), and an emission factor for CBM (1,849 Mcf per completion) were generated.[12] A final emission factor was then determined using a weighted average based on ratios of production from each formation to the total production from CBM, shale, and tight sands (see Table 1-6). The resulting emission factor was about **9,984 Mcf per completion**. Including the URS data, the calculated factor is 7,554 Mcf per completion.

This alternative factor has the advantage of having no over-representation of a given formation type due to greater number of data sets or wells. This method recognizes within the calculation methodology that formation can be a significant variable affecting the total emissions per completion. However, a ratio of gas production may not be a good surrogate for a ratio of completion flowback volumes. In addition, a ratio of gas production might not be representative of the current completions being carried out in each formation.

[12] Including the URS, the calculated emissions rate for tight sands is 8,010 Mcf/completion and for shale is 9,111 Mcf/completion. The URS data set did not include data on CBM, so that rate is unaffected.

Table 1-6: Summary of Data Used for Weighting of Alternative Factor 3

Formation Type	U.S. Gas Production (Mcf/year)	Fraction of Average Production Flow Rate
Tight Sands	6,287,544,084	0.49
Shale	4,656,526,998	0.37
CBM	1,773,088,295	0.14
U.S. Total Gas Production	12,717,159,377	1.0

1.3.3.2 Alternative Factor 4: Weighting by 3 formation types, based on the number of completions for each formation type

The same calculated emissions rates for each of the three formation types used to calculate Alternative Factor 3 were used to calculate Alternative Factor 4. A final emission factor was then determined using a weighted average based on the number of well completions carried out in each formation according to the NEMS models (see Table 1-7). The resulting emission factor was about **9,263 Mcf per completion**. Including the URS data, the value is 6,864 Mcf per completion.

Table 1-7: Summary of Data Used for Weighting of Alternative Factors 4 and 5

Formation Type	U.S. Gas Completion Counts	% of Total
Tight Sands	2,393	26.5%
Shale	4,196	46.5%
CBM	2,426	26.9%
U.S. Total Gas Completions	9,015	100%

This alternative factor has the advantages of having no over-representation of a given formation type due to greater number of data sets, and that it represents current trends in the natural gas industry based on the formations being developed. This method recognizes within the calculation methodology that formation can be a significant variable affecting the total emissions per completion. This method also weighs by the number of completions by formation type, which is more closely corresponds to total completion emissions per formation, than production by formation.

1.3.3.3 Alternative Factor 5: Weighing by 2 formation categories (CBM and tight sands/shale), based on number of completions in formation categories

As data for tight sands and shale showed similar levels of emissions, EPA evaluated an option that treated the two formation types as one. To develop the fifth alternative emission factor for analysis, the data was first separated into one of two groups according to formation: tight/shale and CBM. An emission factor for tight sands/shale (11,025 Mcf per completion)[13] and an emission factor for CBM (1,849 Mcf per completion) were generated.

A final emission factor was then determined using a weighted average based on the number of well completions carried out in each formation according to the National Energy Modeling System (NEMS) models. The resulting emission factor was about **8,538 Mcf per completion**. Including the URS data, the factor is 7,466 Mcf per completion.

This alternative factor has the advantages of having no over-representation of a given formation type due to greater number of data sets, and that it represents current trends in the natural gas industry based on the formations being developed. This method recognizes within the calculation methodology that formation can be a significant variable affecting the total emissions per completion, but that emissions from tight sands and shale formations may not be significantly different. This method also weighs by the number of completions by formation type, which is more closely corresponds to total completion emissions per formation, than production by formation.

1.4 Final Emission Factor

The EPA evaluated all of the data (both data used to develop the original factor and data from the commenters) in several ways to determine whether an improved emission factor could be developed. Every calculation methodology considered had positive and negative aspects with respect to arriving at a single average emissions factor to represent U.S. flowback emissions following hydraulic fracture of a gas well. Excluding the URS data, 3 of the 5 analyses produced factors higher than the 9,175 factor, and 2 produced lower results. Including the URS data, 1 of the analyses produced a factor higher than 9,175, and 4 analyses produced factors lower than 9,175.

[13] Including the URS data, this value is 9,969 Mcf/completion.

1.5 Summary of Evaluation

Table 1-11: Summary of Results

Alternative Factor Number	Description	Factor Value (Mcf/completion)
1	Average by Well Completion	20,574
2	Average by Data Source	6,725
3	Weighting by 3 formation types based on production per formation type	9,984
4	Weighting by 3 formation types, based on the number of completions for each formation type	9,263
5	Weighing by 2 formation categories (CBM and tight sands/shale), based on number of completions in formation categories	8,538

The alternative factors weighted by formation type have the advantage of having no over-representation of a given formation type due to greater number of data sets or wells. These methods recognize within the calculation methodology that formation can be a significant variable affecting the total emissions per completion. The factors weighted by formation type were very similar to EPA's emission factor of 9,175.

The five different calculation methodologies incorporating new data submitted through NSPS comments result in emission factors that fall within the expected interval estimate calculated for EPA's original factor in section 1.6 below. Additionally, EPA's original factor is closest to the results produced when formation type is taken into account, which is a key factor in influencing the emission rate. As a result of this analysis EPA concludes that, although it does have uncertainty, the original EPA emission factor provides a valid central estimate of emissions from this source in the U.S. Therefore, EPA has decided to retain the data set and the methodology used to develop the original emission factor of 9,175 thousand cubic feet (Mcf) per completion.

EPA acknowledges that it did not apply a consistent approach to rounding of significant figures in each individual steps of the original calculation. To address this inconsistency, EPA is making a minor revision by rounding the end result to 1 significant figure. **The final emission factor is 9,000 Mcf per completion.**

1.6 Statistical Analysis: Development of a Bayesian Posterior Interval for the Emission Factor for Hydraulically Fractured Well Completions

<u>Overview</u>
EPA conducted a statistical analysis of the data and developed a Bayesian posterior interval to assess the validity of the emission factor for hydraulically fractured completions. This section describes that analysis.

Data Set for Analysis
As described above, the development of the emission factor of 9,175 Mcf per completion used data from four data sets, together representing data from over 1,000 well completions with hydraulic fracturing. To calculate a robust interval estimate for the emission factor EPA used data on emissions reductions reported by industry to EPA's Natural Gas STAR program. The data set includes several years of data, and contains 56 data entries on reductions from over 9,000 completions at wells with hydraulic fracturing. This larger data set was able to provide a robust interval estimate for the emission factor.

As will be shown in this section, the distributional characteristic of the Gas STAR data appeared to be similar in nature to the data used to calculate the emission factor. Based on these statistical similarities it is justifiable to use the Gas STAR data to construct prior distributions for purposes of improving the estimate of variance and interval estimates centered on the emission factor. Specifically, the Gas STAR data is used to estimate the variance of the emission factor.

Gas Content
The emission factor of 9,175 Mcf per completion represents total potential gas emissions. The Gas STAR data represents potential methane emissions (i.e., a subset of the total potential gas emissions). To develop a meaningful comparison for the purposes of this analysis, we've converted the 9,175 Mcf whole gas emission factor to a methane emission factor of 8,900 Mcf CH_4 per completion, using a methane content value of 83.24% (ECR 2011) and the same averaging and rounding methodologies that were used in the calculation of the 9,175 factor. More detail is presented below.

Within Data Set Variation
Due to the nature of the data—data entries in Gas STAR are aggregate, not at the well-level--a within data set estimate of variance was unobtainable. All estimates of variance explored here are due to between data set variability. For this reason, it is possible that the overall variance presented in this section is an underestimate of the true amount of variability. However, if the between source variability is significantly greater than the within source variability then the bias in the variance is likely to be small.

Bayesian Model

A relatively simple model was chosen for purposes of analysis[14]. The four observations of the emission factors data are assumed to be normally distributed with a mean of μ and a known variance of σ^2 set equal to the sample variance. From prior knowledge, it is reasonable to assume that the mean μ is normally distributed with known mean μ_0 and variance τ^2. The mean of the prior distribution will be set to the mean of the sample, which is the current emission factor, converted to Mcf CH_4 per completion, of 8,900. As a result, the posterior distribution will be normal with a mean equal to the emission factor (8,900) and variance that is a sum of inverse of the prior variance, τ^2, and the inverse of the sample variance, σ^2/n . The sample size for the emission factor data set is 4. Therefore the posterior variance of the emission factor is:

$$\sigma_{EF}^2 = \frac{1}{\left(\frac{1}{\tau^2} + \frac{4}{\sigma^2}\right)}$$

Note that the sample size is 4. The interval estimate will be based on the posterior distribution of the mean.

Datasets

Emission Factor Data
Information from the 4 data sets used to calculate the emission factor is shown in Table 1-8 below. The data sets together represent emissions calculated for over 1,000 well completions; however, not all of the data sets presented well-level information. As such, we were unable to analyze the within data set variance. The values presented below are the average emissions for each data set. The column labeled 'Whole Gas' shows the value used to develop the Mcf gas per completion value of 9,175. The column labeled 'Modified' is the Whole Gas column multiplied by the methane content correction factor of 0.8324. The final column labeled 'Rounded' is the values that are used to calculate the emission factor.

Table 1-8. Data Used to Calculate the Emission Factor

Data Source	Whole Gas	Modified	Rounded
Weatherford	667	555	600
Industry Data Set #1	5,820	4,844	5,000
Devon	11,900	9,905	10,000
William	24,449	20,351	20,000

The average of the four rounded values is 8900 and the standard error is 4,168. Due to the small number of data sets (4) the confidence interval around the emission factor that is very wide.

[14] Gelman, Andrew; Carlin, John B.; Stern, Hal S.; Rubin, Donald B. (2003). Bayesian Data Analysis, Second Edition. Boca Raton, FL: Chapman and Hall/CRC. ISBN 1-58488-388-X.

Using the standard distributional assumptions, the 95% confidence interval based on the 4 data sets is:

$$\bar{x} \pm t_{3,.025} SE(\bar{x})$$

where $t_{3,.025}$ is a value from the T-distribution with 3 degrees of freedom. The values for $\bar{x}$ and $SE(\bar{x})$ are given in Table 1-9. Using these values the 95% CI for the current emission factor is (-8,510, 26,100). In the sections below the goal will be to obtain a more useful interval estimate for the emission factor.

Table 1-9. Descriptive Statistics for Emission Factor Data

Observations	4
Minimum	555
Maximum	20,351
Mean	8,900
Variance	6.95+07
Standard Error	4168.5

Gas STAR Data

A key assumption for employing Bayesian analysis in this situation is that the data used to calculate the emission factor should have a similar distribution to the Gas STAR data. If this assumption appears to be reasonable then the Gas STAR data can be used to create a prior distribution for the emission factor. In order to provide justification for this assumption the means, variances and ranges of the Gas STAR data are compared to the emission factor data. The Gas STAR data set reviewed contained 55 data entries with information on completion type. The Williams observation, which was included in both the emission factor and in the Gas STAR data set, was removed from the Gas STAR data for purposes of calculating theses statistics which are shown in Table 1-10. Inclusion of this observation would imply that the statistics calculated using the Gas STAR data are correlated with statistics from the emission factor data. This type of correlation would make the analysis needlessly complicated.

Table 1-10. Descriptive Statistics for all Gas STAR Data

Observations	55
Minimum	76
Maximum	65,322
Mean	9,174
Variance	1.25E+08

Mean

The mean of the Gas STAR data is 9,174 Mcf CH4 per completion, which compares favorably to the converted methane emission factor of 8,900. Given the amount of variability in the data, these values are statistically equivalent.

Range

The range of observations for the emission factor data are (555, 20,351) and for Gas STAR the range is (76, 65,322). It should be noted that the second largest value in the Gas STAR data is

27,305. While the range of the Gas STAR data appears to be greater than the emission factor data, it appears to be a function of one large observation. If that observation is removed then the ranges of the two datasets are nearly identical. The minimum for the emission factor data is 555. Of the 55 Gas STAR observations only 6 have a value less than 555. This implies that the value of 555 is not an expected minimum when only four observations are in the sample.

Variance of the Mean
Assuming that the observations in the Gas STAR dataset are independent and identically distributed, the variance of the mean is calculated by dividing the variance shown above by the sample size. Thus:

$$\hat{\tau}^2 = \frac{124733847}{55} = 2{,}267{,}888$$

The standard error of the mean is the square root of this value which is 1,506.

Corrected Standard Error for the Emission Factor
The estimate of the standard error for the emission factor $\hat{\sigma}_{EF}$ can now be determined using the Gas STAR information and the emission factor data. This will be done by using Bayesian analysis. The Gas STAR data will be used to create a normal prior distribution for the mean emission factor value. This prior will has a mean of 8900 and variance τ^2 as defined above. The new variance of emission factor the will be determined using the following formula:

$$\hat{\sigma}_{EF}^2 = \frac{1}{\left(\frac{1}{\hat{\tau}^2} + \frac{4}{\sigma^2}\right)}$$

where s^2 is the variance of four emission factor observations (6.95E7). This gives:

$$\hat{\sigma}_{EF}^2 = 2{,}006{,}067$$

And

$$\hat{\sigma}_{EF} = 1416.3$$

The posterior distribution for the emission factor is then N(8,900, 2,006,067). The 95% prediction interval is

$$8900 \pm 1.96 * 1416.5$$

This gives bounds of (6,123, 11,676).

Summary of Results
The 95% posterior interval for the converted methane emission factor of 8,900 Mcf methane per completion was determined to be (6,123, 11,676). As this is a Bayesian interval estimate the interpretation is there is a probability of 0.95 that the true emission factor is between 6,123 and

11,676 given that the posterior distribution for the emission factor is N(8,900, 2,006,067).

The posterior interval shown above is calculated for the methane emission factor of 8,900. It is likely that the emission factor of 9,175 Mcf whole gas per completion, and the rounded factor of 9,000 Mcf whole gas per completion, would have a similar interval estimate as that of the methane emission factor. The center of the two interval estimates would clearly be similar (8,900 versus 9,000 or 9,175). However, it is likely that the whole gas interval would be wider as the variance would likely be larger. As a result, it is reasonable to assume that probability that the true emission factor for whole gas being contained in the interval 6,123 and 11,676 is similar to 0.95.

2.0 NSPS LOW PRESSURE COMPLETION THRESHOLD

2.1 Overview

Many commenters stated that not all gas wells have the necessary reservoir pressure to flow at rates appropriate for transporting solids and liquid from a hydraulic fractured gas well completion into an imposed back-pressure. One commenter provided an analysis recommending an applicability cut-off to exclude wells that do not have sufficient reservoir pressure to flow into a gathering line. In light of these comments this analysis evaluates the minimum flowback pressure determination to provide facilities subject to the well completion NSPS rule a means to determine when flowback gas at a facility has sufficient pressure to flow into a flow line, and when a facility does not have sufficient pressure, in which case the flowback gas must be diverted to a combustion device. This section describes the flowback condition being investigated by detailing the three flow regimes encountered during the flowback event within the horizontal and/or vertical span of a well's tubing:

2.2.1 Fracture Fluid Flow

After hydraulic fracture (frack) of a new or existing well, the well tubing is filled with frack fluid which consists of thousands of barrels of injected liquid, i.e. water (plus additives) and proppant, i.e. typically sand. This material must be evacuated to prepare the well for production. When the flowback is initiated, the vertical column of frack fluid in the tubing is being acted upon by the forces of:

- the weight of the frack fluid column in the well tubing,
- friction from the tubing walls opposing the flow to the surface,
- the pressure of the gas in the formation,
- the pressure that the formation rock exerts on the frack fluid within the fracture zone(s),
- for energized fracks, the pressure exerted by the inert gas introduced into the reservoir ahead of or with the frack water
- the pressure drop through surface equipment connected to the well which may include separators and temporary flow lines, and
- the backpressure of the gas gathering destination of the flowback gas

During the initial flowback, virtually all of the flow output from the well consists of the frack material itself, rather than hydrocarbons from the formation, given that the well tubing is filled with the frack fluid. During this initial flow of only frack fluid, the pressure opposing the direction of the flowback is highest given that the vertical distance of the tubing completely filled with frack fluid. For this analysis the density is assumed to be that of the water/sand that is present rather than with any vapor which has a lower density. As the frack fluid reaches the surface, it is typically directed to atmospheric pressure storage, typically in a tank.

2.2.2 Slug Flow

As the column of frack fluid flows to the surface, it is replaced with gas (hydrocarbon from the formation and/or inert gas introduced during the frack) that enters the well tubing and flows upward towards the wellhead. The presence of the gas in the tubing, where gas has replaced liquids, decreases the weight of the material in the vertical column. As the slug flow reaches the surface, it is directed to temporary storage where the liquids portion of the slug flow is contained while the gas portion of the slug flow typically vents the atmosphere or a combustion device. Because the low density and viscosity of the flowback gas relative to the frack fluid (water) there is substantial bypassing of gas and liquid such that the flowing fluid is multi-phase slugs of gas and liquid.

2.2.3 Steady Flow of Vapor

As the frack fluid in the tubing is pushed out and replaced with vapor and frack fluid from the fracture zone in the reservoir formation, the initial steady flow of liquid transitions to slug flow of frack fluid and vapor. Over time (on the order of hours to days), the slug flow transitions to a steady flow condition where the frack fluid slugs in the tubing have been largely evacuated and there is a reasonably steady flow of a continuous vapor phase entraining droplets of water and/or condensate. For energized fracks, this steady flow of vapor may, for a time, contain a significant percentage of the inert gas introduced into the formation during the frack, and over time, (on the order of hours) the steady flow of vapor transitions to primarily hydrocarbons from the formation. Depending upon the pressure of the gas after it flows to the wellhead and through any potential REC equipment, the steady flow of gas can be directed to surface equipment and then to a combustion device or to the flow line.

The minimum pressure equation developed in the next section applies to the steady flow of vapor condition encountered during the flowback since this is the flow that may be capable of being routed to the flow line (although an REC may be physically capable of diverting some gas from the slug flow condition into sales).

2.2 Development of the Pressure Equation

To determine whether the flowback gas at a facility has sufficient pressure to flow into a flow line, a model was developed to calculate the pressure for flowback gas exiting a well in steady flow, given its reservoir pressure and depth. The model requires inputs for the reservoir pressure and for the well vertical depth, which are expected to be known before the flowback occurs. The model uses an established quantitative relationship for fluid flow during well cleanups to determine the gas velocity of a well during the steady flow condition of the flowback. The model then uses an energy balance to determine the pressure drop based on the calculated velocity, and then the model accounts for pressure losses of surface equipment. The result of the model is a prediction of the pressure of the flowback gas immediately before it enters the flow line. The result can be compared to the actual flow line pressure available to the well. For wells with insufficient predicted pressure to produce into the flow line, combustion can be specified as the control standard. For wells with sufficient pressure to produce into the flow line, gas capture in combination with combustion can be specified as the control standard.

This section describes the steps taken to develop such a model in the following sections:

2.2.1 Pressure Drop Theory introduces the engineering principles for the model and the model's structure.

2.2.2 Model Parameter Definitions and Assumptions defines all the parameters in the model and the associated assumptions.

2.2.3 Final Numerical Model combines the theoretical basis and the parameter definitions to create the complete model.

2.2.4 Linear Regression of Numerical Model Results develops a practical equation that can be used in the rule based on outputs of the pressure drop model.

2.2.5 Incorporation of Pressure Threshold Equation into the Rule describes how the linear equation is used in the rule.

2.2.1 Pressure Drop Theory

The pressure of the flowback gas at the flow line during the steady flow condition is determined primarily by the reservoir pressure and the depth of the well. Starting at the reservoir pressure, the pressure of the flowback gas decreases due to energy losses as it travels through the reservoir and into the tubing (including any horizontal segment), up the tubing, and through the surface equipment. This section describes the fundamental structure of the model, which is based on the pressure decrease as the gas travels through the reservoir, the tubing, and the REC equipment.

2.2.1.1 Pressure Decrease in Reservoir

The change in pressure as the gas travels through the reservoir is difficult to determine analytically because it varies from reservoir to reservoir and is dependent on the porosity and transport efficiency within the reservoir and near the wellbore. In addition, there is little public data available to determine the change in pressure from the reservoir to the bottom of the well at a national level. This analysis accepts the assumption for the pressure change from the reservoir to the wellbore provided by the American Petroleum Institute (API) in its comments on the proposed NSPS OOOO ruling[15]. API stated that, "…it is not unusual for the required reservoir pressure to be more than twice the bottom hole pressure…" Considering the API comment, this analysis conservatively assumed the reservoir pressure to be twice the bottom hole pressure. Accordingly, Equation 2-2 determines the bottom hole pressure (pressure of the gas at the bottom of the tubing at the perforations) given the reservoir pressure by dividing the reservoir pressure by two.

$$P_{BH} = {}^{P_R}/_{2} \qquad \textbf{(Eq. 2-2)}$$

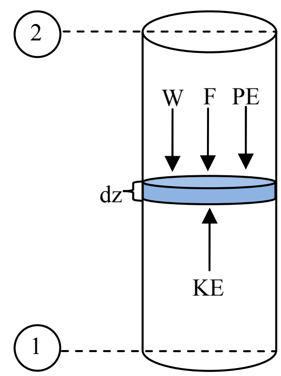
2.2.1.2 Pressure Decrease along Well Tubing

[15] Comment submitted by Howard J. Feldman, Director, Regulatory and Scientific Affairs, American Petroleum Institute (API) www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-4266

As the flowback fluid travels from the bottom of the tubing, through the tubing, and to the wellhead, the gas experiences further pressure losses. This pressure decrease can be modeled using an energy balance. Since energy must be conserved along the tubing (i.e. the energy into the system is equal to the energy out of the system), an energy balance can be constructed to characterize the energy acting on the fluid and the energy leaving the fluid moving within the tubing. This fundamental energy balance is shown in Equation 2-3. The integration sign in Equation 2 indicates that the kinetic energy, potential energy, work, and friction losses are analyzed as they change from point 1, the bottom of the tubing, to point 2, the surface. The kinetic energy, potential energy, work, and friction losses are then determined for each segment and summed over the entire tubing length. Figure 2-1, shows a visual depiction of the energy balance in Equation 2.

$$\int_1^2 (KE + PE + W + F)dz = 0 \qquad \textbf{(Eq. 2-3)}$$

Figure 2-1. Visual Representation of an Energy Balance Across a Vertical Tubing



where,

KE = specific kinetic energy of the fluid, ft/s^2

PE = specific potential energy of the fluid, ft/s^2

F = energy lost from the fluid due to friction, ft/s^2

W = specific work performed by the fluid, ft/s^2

dz = height of an infinitesimal section of the tubing, ft

The kinetic energy (*KE*) of the fluid is defined as $u\frac{du}{dz}$, where *u* is the velocity of the fluid, in feet per second (ft/s), and *du* is the change in velocity of the fluid, in ft/s. The specific potential energy (*PE*) of the fluid is defined as $-\text{g} \cos\theta$, where θ is the angle of the tubing with respect to the vertical (for a vertical tubing as assumed here θ = 0), in radians and *g* is gravitational acceleration, in ft/s^2. Specific work (*W*) is defined as $-\frac{1}{\rho}\frac{dP}{dz}$ where *dP* is the change is pressure, in absolute pounds per square inch (psia), and *ρ* is the density of the fluid, in cubic feet per pound mass (ft^3/lbm). Specific friction loss (*F*) is defined as $\frac{-fu^2}{2D}$ where *f* is the Moody friction factor, *u* is the velocity of the fluid, in ft/s, and *D* is the diameter of the tubing, in feet. Plugging these definitions for *KE*, *PE*, *W*, and *F* into Equation 2 yields Equation 2-4.

$$\int_1^2 udu - \frac{dP}{\rho} + \left(-g\cos\theta - \frac{fu^2}{2D}\right)dz = 0 \qquad \textbf{(Eq. 2-4)}$$

Since this analysis is determining the pressure of the gas at the flow line, the *dP* term is of most interest. Also, *du* is assumed to be negligible since the tubing has a constant cross sectional area and since dz is taken to be a small interval. This assumption is corroborated by the *Natural Gas Engineering Handbook*[16] and *Perry's Chemical Engineering Handbook*[17]. Finally, the tubing is assumed to completely vertical, which means θ is equal to zero. Therefore, Equation 3 is solved for dP with udu and θ set equal to zero, yielding Equation 2-5. Equation 2-5 is the basis for the calculation to determine the change in pressure from bottom-hole to the wellhead. Equation 4 can be found in the *Natural Gas Engineering Handbook* and *Perry's Chemical Engineering Handbook*.

$$\int_1^2 dP = \int_1^2 -\left(\rho g + \frac{\rho f u^2}{2D}\right) dz \qquad \textbf{(Eq. 2-5)}$$

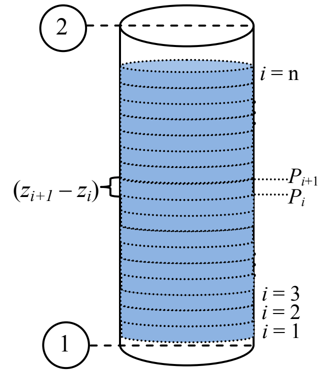
Equation 4 is a differential equation governing the pressure change of a fluid over a length of vertical well tubing. As shown in Appendix B.1, the density of the fluid, a mixture of natural gas, water, and sand, is a function of the temperature and pressure of the fluid, which change as the fluid moves up the tubing. In addition, the velocity is a function of the density. Based on these factors, an analytical solution of Equation 2-5 is not possible. Instead the equation is solved numerically with the known values of the parameters in a preceding fluid segment used to calculate the values in the next segment. This numerical integration process yields the pressure drop across the tubing.

Numerical integration is an approximation method which involves dividing a tubing of a given length into a finite number of segments, applying Equation 2-5 to each segment, and solving for the pressure exiting each segment in sequence beginning from the bottom. This is shown in Equation 2-6 and Figure 2-2. The pressure exiting a segment is assumed to be the pressure entering the following segment. The pressure exiting a segment is also used to determine the density and velocity of the natural gas in the following segment. The pressure change from the first segment at the bottom of the well to the last segment as the surface is equal to the pressure drop over the entire tubing length, as shown in Equation 2-7. Numerical integration is an approximation method used to solve complex integrals, which approaches the true integral solution as the height of each segment ($z_{i+1} - z_i$) or dz approaches zero.

[16] Guo, B. Ghalambor, A. (2005) *Natural Gas Engineering Handbook*. Gulf Publishing Company. pg. 52.
[17] Perry, R.H. (1963). *Perry's Chemical Engineers' Handbook* (4th Edition). McGraw-Hill. Equation 5-58. pg. 5-23, Covert Fanning *f* to Moody *f*.

$$P_{i+1} = P_i - \left(\rho_{MPi} g + \frac{\rho_{MPi} f u_i^{\,2}}{2D} \right) (z_{i+1} - z_i) \quad \textbf{(Eq. 2-6)}$$

Figure 2-2. Visual Representation of the Numerical Integration of a Vertical Tubing



$$P_{WH} = P_{BH} - \sum_{i=0}^{n} \left(\rho_{MPi} g + \frac{\rho_{MPi} f u_i^{\,2}}{2D} \right) (z_{i+1} - z_i) \quad \textbf{(Eq. 2-7)}$$

where,

P_{i+1} = Pressure fluid exiting segment *i*, in psia

P_i = Pressure of fluid entering segment *i*, in psia

n = number of segments

$(z_{i+1} - z_i)$ = height of segment *i* or length of tubing divided by *n*, in feet

ρ_{MPi} = density of the multiphase fluid, in pounds per cubic feet

P_{WH} = pressure of fluid at the wellhead

P_R = bottom hole pressure, pressure of the fluid at the perforations

Equation 2-6 is solved *n* times (i.e., for each segment) to determine the pressure drop across a tubing with a given length and bottom hole pressure as shown by the summation term in Equation 2-7. Section 2.2 defines each parameter in Equation 2-6 and Equation 2-7 in order to solve for P_{i+1} and subsequently P_{WH}.

2.2.1.3 Pressure Decrease along REC Equipment

The pressure of the flowback gas decreases further as it passes through the reduced emission completion recovery equipment and/or other surface equipment after exiting the wellhead but before entering the flow line that leads to sales and/or the gas gathering system. This decrease in pressure from surface equipment is small compared to the decrease occurring as the gas flows from the reservoir to the wellhead. This analysis assumes that the ratio of the pressure before the REC equipment (the wellhead pressure) and the pressure after the REC equipment (the flow line pressure) is constant at 1.01. Therefore, given the wellhead pressure, the pressure immediately before the flow line can be determined using the Equation 2-8.

$$P_L = {}^{P_{WH}}\!/_{1.01} \quad \textbf{(Eq. 2-8)}$$

where,

P_L = the pressure of the fluid immediately before the flow line

P_{WH}= pressure of fluid at the wellhead

2.2.2 Parameter Definitions and Assumptions

This section defines the parameters in Equations 2-6 and 2-7 to solve the pressure drop across each segment in the numerical integration described previously. The key parameters in Equations 2-6 and 2-7 are the density of the moving fluid ρ, the velocity of the fluid u, the Moody friction factor f, and the inner tubing diameter D. The methodology to determine a value for each of these parameter is discussed in the sections below. The nomenclature for all the variables discussed is at the end of each section.

2.2.2.1 Defining Fluid Density

The fluid inside the well tubing during the steady flow regime is a mixture of natural gas, water, and sand. This analysis assumes that the multiphase fluid acts like a single phase fluid within each segment ($z_{i+1} - z_i$) and has a density equivalent to the weighted average of the densities for each of the components. This assumption allows for the use of the Tuner Equation, explained in section 2.2.2 for determining the velocity of the fluid travel up the well bore. Equation 2-9 shows how the density of the mixture is calculated based on the densities of the natural gas, water, and sand weighted by their volume percent.

$$\rho_{MPi} = \rho_{gi}\left(1 - f_{liquid}\right) + \left(\rho_{water} f_{water} + \rho_{sand} f_{sand}\right) f_{liquid} \qquad \textbf{(Eq. 2-9)}$$

The density of the fracture sand, ρ_{sand}, is assumed to be that of silica (i.e. SiO_2), the primary constituent of sand typically used to fracture gas wells. As *Industrial Minerals* states "Frac sand must be >99% quartz or silica [SiO_2]."[18] The fraction of sand in the water sand mixture (f_{sand}) was assumed to be five percent by volume based on expert judgment. The fraction of water and sand in the flowback fluid (f_{liquid}) was assumed to be 5 percent by volume.
Equation 2-10, the derivation of which is shown in Appendix B.1, shows that the density of the natural gas in the gas-water-sand mixture is determined using the pressure at segment i, the molecular weight of natural gas (MW), the compressibility factor (Z_i), the gas constant (R), and average fluid temperature (T).

$$\rho_{gi} = \frac{P_i(MW)}{Z_i RT} \qquad \textbf{(Eq. 2-10)}$$

The molecular weight (MW) of the natural gas was assumed to be 16 pounds per pound-mole (lb/lb-mol) representing the molecular weight of methane, the primary constituent of natural gas.

[18] Zdunczyk, M. (2007) "The Facts of Frac" *Industrial Minerals.* Jan. 2007 <www.indmin.com/Article/1913170/The-facts-of-frac.html>

The natural gas compressibility factor for a given well segment i (Z_i) determined in this analysis using the Brill and Beggs correlation[19]. A second correlation, the Pitzer correlation[20], was also performed to calculate a compressibility factor for each well segment for validation purposes, and the two correlations were found to agree within 10 percent for pressures 3000 psi or less. A more detailed investigation of alternative methods for calculating the compressibility factor can be found in Appendix B.4. The compressibility factor accounts for the deviation of a gas from the characteristics of an ideal gas. The compressibility factor is a function of the pressure of the gas, temperature of the gas, and the composition of the gas. In this analysis, the compressibility factor was determined for each segment using the pressure at each segment, the average temperature of the fluid, and the average CO_2, H_2S, and N_2 composition of the gas. The CO_2, H_2S, and N_2 composition in the gas was determined using a technical memo published in the NSPS OOOO rule making docket titled "Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking."

The average temperature (T) of the fluid was assumed to be 200 °F based on expert judgment. This was held constant over the entire numerical integration. The gas constant (R) is universal and is equal to approximately 10.73 ft^3 psia $°R^{-1}$ $lb\text{-}mol^{-1}$.

Table 2-1 summarizes the values selected to determine the density of the flowback fluid for each segment.

Table 2-1. Summary of Parameters to determine Flowback Fluid Density

Parameter	Description	Method	Value
P_i	pressure of gas	Calculated by Equation 5	Varies for each segment
MW	molecular weight of the gas	Assumption	16 lb/lb-mol
T	temperature of the gas	Assumption	200 °F
Z_i	compressibility factor of the gas at P_i and T	Brill and Beggs Correlation	Varies for each segment with pressure (P_i)
R	universal gas constant	Universal constant	10.73 ft^3 psia $°R^{-1}$ $lb\text{-}mol^{-1}$
ρ_{MPi}	density of the flowback fluid, pounds per cubic feet	Calculated by Equation 8	Varies for each segment with pressure (P_i)
ρ_{sand}	density of proppant, pounds per cubic feet	Assumed to be same as pure silica (SO_2)	165 lbm/ft^3
ρ_{water}	density of water, pounds per cubic feet	Standard density of H_2O at STP	62 lbm/ft^3
ρ_{gi}	density of gas at P_i and T, pounds per cubic feet	Calculated by Equation 9	Varies for each segment with pressure (P_i)
f_{water}	fraction of water, by volume, in water-sand mixture	Assumption	95%

[19] Brill, J. P., and H. D. Beggs. "Two-Phase Flow in Pipes." INTERCOMP Course, The Hague, 1974.
[20] J.M. Smith, H.C. Van Ness, M.M. Abbott. (2005). *Introduction to Chemical Engineering Thermodynamics*. McGraw-Hill.

f_{sand}	fraction of sand, by volume, in water-sand mixture	Assumption	5%
f_{liquid}	fraction of water-sand mixture in fluid, by volume, in flowback fluid	Assumption	5%

2.2.2.2 Defining Fluid Velocity

The velocity of the fluid in each segment of the tubing is determined assuming the operator needs to maintain sufficient flow to clean up the well of the water and proppant mixture. This is determined using the entrained drop model developed by R.G. Turner[21] specifically with well cleanup in mind. This model, henceforth referred to as the Turner velocity model, determines the minimum gas velocity needed to lift fluid of a known density from inside a well bore. The Turner velocity model was adapted in this analysis to determine the minimum velocity needed to lift flowback material out of the well, where all of that flowback material was conservatively assumed to have the density of the most dense component, which in this case is the sand. This adapted Turner velocity model is shown in Equation 2-11.

$$u_i = 1.3 \frac{\sigma^{1/4} \left(\rho_{sand} - \rho_{gi}\right)^{1/4}}{C_d^{1/4} \rho_{gi}^{1/2}} \qquad \textbf{(Eq. 2-11)}$$

Equation 2-11 determines the minimum velocity to lift a droplet of the flowback material assuming the density of the droplet is equivalent to that of sand. The surface tension coefficient (σ) and drag coefficient (C_d) in Equation 2-11 are assumed to be the same assumed by R.G. Turner for water since we expect flowback water to collect around the sand particles during the cleanup. R.G. Turner also adjusts the velocity calculated by the equation upward by 20% to match field data; this analysis accepts this adjustment which is already incorporated into Equation 2-11.

Since the density of the gas (ρ_{gi}) changes for each tubing segment in the numerical integration, the minimum gas velocity also changes for each step in the numerical integration. The surface tension coefficient (σ) and drag coefficient (C_d) remain constant.

Table 2-2. Summary of Parameters to determine Flowback Fluid Velocity

Parameter	Description	Method	Value
u_i	Turner velocity, minimum gas velocity needed to lift a droplet	Calculated by Equation 10	Varies for each segment with density (ρ_{gi}) and pressure (P_i)
σ	surface tension of water, dynes per centimeter	Accepted value from R.G. Turner	60 dynes/cm

[21] Turner, R. G. *et. al.* Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells. *Journal of Petroleum Technology.* Nov. 1969. Equation 4, pg. 1476

C_d	drag coefficient of water	Accepted value from R.G. Turner	0.44
ρ_{sand}	density of proppant, pounds per cubic feet	Assumed to be same as pure silica (SO_2)	165 lbm/ft^3
ρ_{gi}	density of gas at P_i and T, pounds per cubic feet	Calculated by Equation 9	Varies for each segment with pressure (P_i)

2.2.2.3 Inner Tubing Diameter

The inner diameter of the tubing was taken to be 2 and 7/8th inches which is a common value for gas wells. The inner tubing diameter remains constant over the entire numerical integration. An additional investigation was conducted to determine if the functional diameter, through which the completion fluid would flow, is smaller than the inner tubing diameter due to significant water plating on the walls of the tubing. It was determined that with a 5 percent fraction of liquid in the flowback fluid, the thickness of the film of water plating the inner tubing wall is at the most 0.035 inches (which is multiplied by two to account for both endpoints of a line passing through the center of the tubing cross section). Since the film of water plating the inner tubing wall is at the most only 2.5% of the tubing diameter it was concluded that the effective tubing diameter was the same as the inner diameter of the tubing. This calculation is shown in Appendix B.2.

Table 2-3. Summary of Parameters to determine the Tubing Diameter

Parameter	Description	Method	Value
D	Inner tubing diameter, inches	Assumption	2.875 inches

2.2.2.4 Defining Friction Factor

The Moody friction factor is a unitless constant that accounts for the friction experienced by the moving fluid in the tubing. The Moody friction factor was determined assuming turbulent flow, which is the case for gas wells, and a correlation equation in the *Natural Gas Engineering Handbook*. Appendix B.3 discusses further how the turbulent flow assumption is valid for gas wells. The Nikuradse[22] friction factor correlation used in this analysis for turbulent flow in rough pipes, shown in Equation 2-12, requires the roughness factor and the tubing diameter to determine the Moody friction factor. This analysis assumes 0.0001 inches for the average roughness. The *Natural Gas Engineering* recommends using a value of 0.006 inches for the roughness of tubing pipes if no information is available[23]. However, since the inner tubing wall will likely be plated with water, the roughness experienced by the gas/water interface is much less than the roughness of the inner tubing wall. Since this analysis also estimates a constant tubing diameter, discussed further below, the friction factor remains constant over the entire numerical integration, the value of which is shown in Equation 2-12.

[22]Guo, B. Ghalambor, A. (2005) Natural Gas Engineering Handbook.Gulf Publishing Company. pg. 54, Equation 4.10.
[23] Guo, B. Ghalambor, A. (2005) Natural Gas Engineering Handbook.Gulf Publishing Company. pg. 204

$$f = \left[\frac{1}{1.74 - 2\log\left(\frac{2\varepsilon}{D}\right)}\right]^2 = \left[\frac{1}{1.74 - 2\log\left(\frac{2(0.0001)}{2.875}\right)}\right]^2 = 0.00989 \qquad \textbf{(Eq. 2-12)}$$

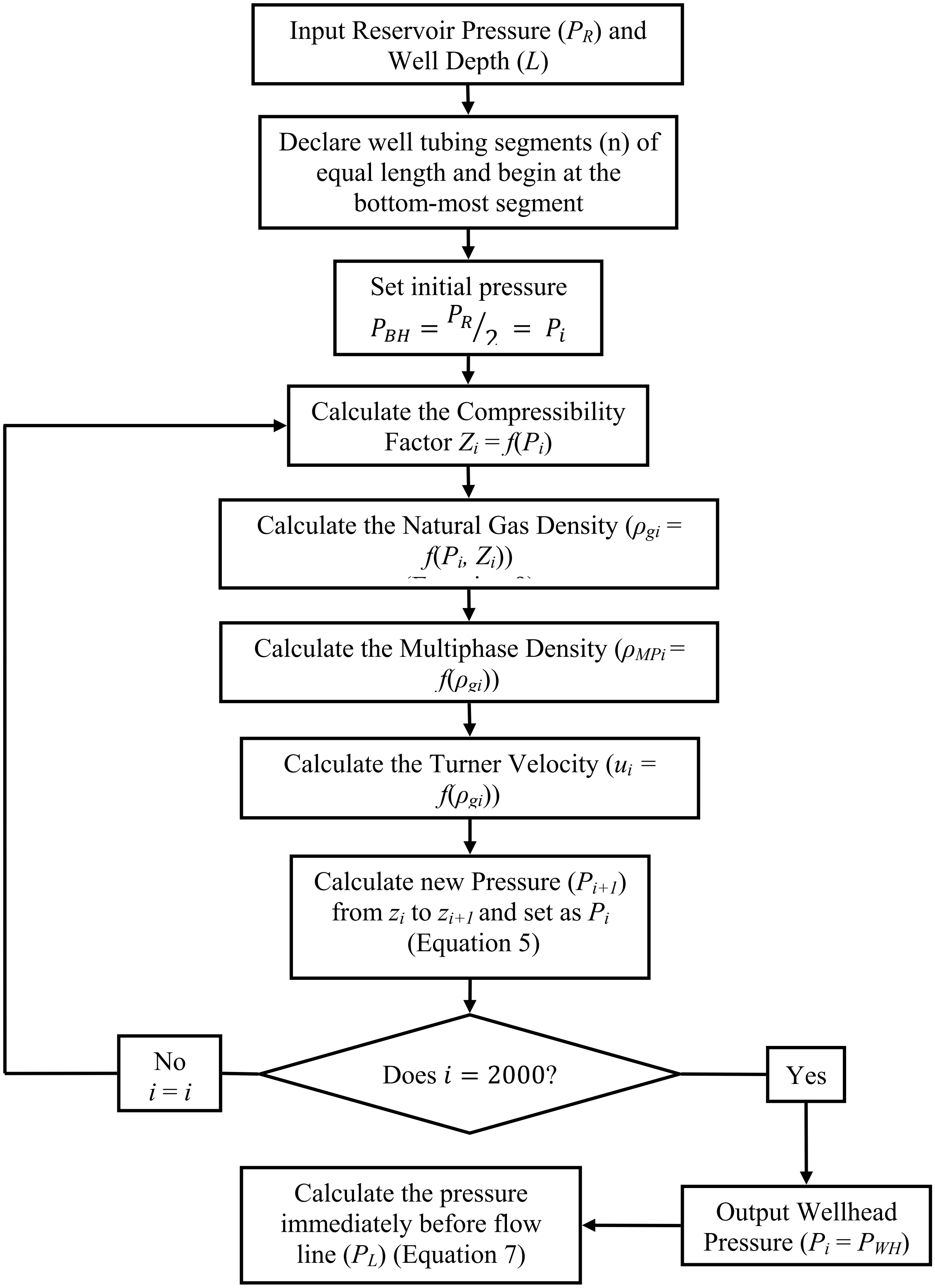
Table 2-4. Summary of Parameters to determine the Moody Friction Factor

Parameter	Description	Method	Value
f	Moody friction factor, unitless	Calculated by Equation 11	0.00989
ε	roughness of inner tubing wall, inches	Assumption	0.0001 inches
D	Inner tubing diameter, inches	Assumption	2.875 inches

2.2.3 Final Numerical Model

The complete model to determine the pressure immediately ahead of the flow line (P_L) of a gas well during its steady flow phase of a cleanup after a hydraulic fracture, given its reservoir pressure (P_R) and well depth (L) is depicted in the block flow diagram in Figure 2-3. First, the reservoir pressure and well depth are inputted. Next, the bottom-hole pressure (P_{BH}) is determined from the reservoir pressure using Equation 2-7, and the well depth is divided into segments for the numerical integration. The number of segments (n) equals the number of steps taken in the numerical integration; this analysis uses n=2,000 steps. The bottom-hole pressure is used to determine the compressibility factor of the natural gas for the first step in the numerical integration (Z_i). Next, the density of the natural gas (ρ_{gi}) is determined for the first step in the numerical integration using the bottom-hole pressure and the compressibility factor, using Equation 2-10. The density of the natural gas is used to determine the velocity of the gas (u_i) using the Turner velocity model in Equation 2-11 and the density of the flow back fluid (ρ_{MPi}) accounting for water and sand using Equation 2-9. Finally, the velocity of the gas and density of the flow back fluid are used to determine the pressure of the gas exiting the first segment (P_{i+1}) using Equation 2-6. The pressure of the gas exiting the first segment is then set equal to the pressure of the gas entering the next segment and the process above is repeated until the sum of the each segment's height is equal to the well depth. The pressure of the gas exiting the last segment is equal to the wellhead pressure (P_{WH}). Finally, the wellhead pressure is used to determine the pressure immediately before the flow line using Equation 2-8.

Figure 2-3. Block Flow Diagram of the Model used to Determine the Pressure Immediately Ahead of the Flow Line, for a Hydraulically Fractured Gas Well Completion Flowback in the Steady Flow Condition



2.2.4 Linear Regression of Numerical Model Results

A linear regression was used to develop a simplified linear equation that yields similar line pressures outputs as the model described above for a given well depth and reservoir pressure. Two steps were taken to arrive at the linear pressure threshold equation in the NSPS OOOO ruling using the results of the numerical model described above.

2.2.4.1 Generate Line Pressures using Numerical Model

First, the numerical model was run for various plausible combinations of well depths and reservoir pressures. Well depths ranging from 500 feet to 20,100 feet in increments of 400 feet and reservoir pressures ranging from 100 pounds per square inch absolute (psia) to 9,850 psia in increments of 250 psia were inputted into the numerical model to determine a line pressure for each combination of well depth and reservoir pressure. The depth and pressure increments used to generate the matrix of test cases are different than the numerical integration increments discussed in section 2.3.3. The matrix of test cases yielded about 2,000 numerical model runs with calculated flowback gas pressures after exiting surface equipment varying from 3 psia to 4,827 psia.

2.2.4.2 Regress the Line Pressure Outputs from the Numerical Model

Second, a regression was developed based on these 2,000 numerical model runs. Some model run flowback gas pressure outputs were low, and some were high, as described in the previous section. Two options were evaluated on how to conduct the regression. One option was to develop a regression over the entire range of model runs so that the standard error would be minimized equally across the range. The second option was to select a subset of the range in which to regress, so that the standard error is minimized in that region of interest. The region of interest in this analysis was the line pressures outputted by the numerical model less than 1,000 psia. The regression was performed on line pressures less than 1,000 psia because most flow lines that will receive flowback back are at less than 1,000 psia. Subsequently, the standard error of the correlation was minimized for line pressures less than 1000 pisa. There were 418 model runs with line pressures less than 1,000 psia. These model runs were regressed against the reservoir pressure and well depth to generate a simple linear equation that estimates the line pressure of a well given its reservoir pressure and well depth. The resulting regression equation is shown in Equation 12.

$$P_L = 0.445 \times P_R - 0.038 \times L + 67.578 \qquad \textbf{(Eq. 2-13)}$$

This regression is an approximation of the numerical model results for line pressures less than 1,000 psia and therefore has an associated error when estimating line pressures. The regression analysis yielded a standard error of 24.3 psia for line pressures less than 1,000 psia, which means the average deviation between the line pressure determined by Equation 12 and the line pressure determined by the numerical model is 24.3 psia for line pressures less than 1,000 psia. Since the regression was performed for line pressures less than 1,000 psia, the standard error increases as the resulting line pressures increase above 1,000 psia.

The coefficient of determination (R^2) is a parameter that quantifies the fit of the regression. The coefficient of determination indicates how well the linear regression equation approximates the model runs regressed. A coefficient of determination equal to one indicates that the line perfectly fits the regressed data, whereas coefficient of determination values less than one indicate a less than perfect fit. The regression performed in this analysis has an R^2 value of 0.992 for flow line pressures less than 1000 psia.

Figure 2-4 compares the line pressures as determined by the numerical model and the linear regression equation. On the x-axis of

Figure 2-4 is a selection of the 2,000 model runs in the region of interest, each assigned a number, representing a combination reservoir pressure and well depth that was inputted into the numerical model and the linear regression equation. For each combination of reservoir pressure and well depth, the numerical model and linear regression equation outputted a flow line pressure, which is plotted on the y-axis in

Figure 2-4. The blue diamonds represent the numerical model line pressures and the red squares represent the linear regression line pressures. Where the red squares and blue dots seem to overlap indicates the numerical model and the linear regression equation outputted similar flow line pressures for the same reservoir pressure and well depth inputs. Conversely, where the red squares and blue dots deviate significantly indicates the numerical model and the linear regression equation outputted different flow line pressures for the same reservoir pressure and well depth inputs.

Figure 2-4. Comparison between Line Pressures from the Linear Regression and Numerical Model

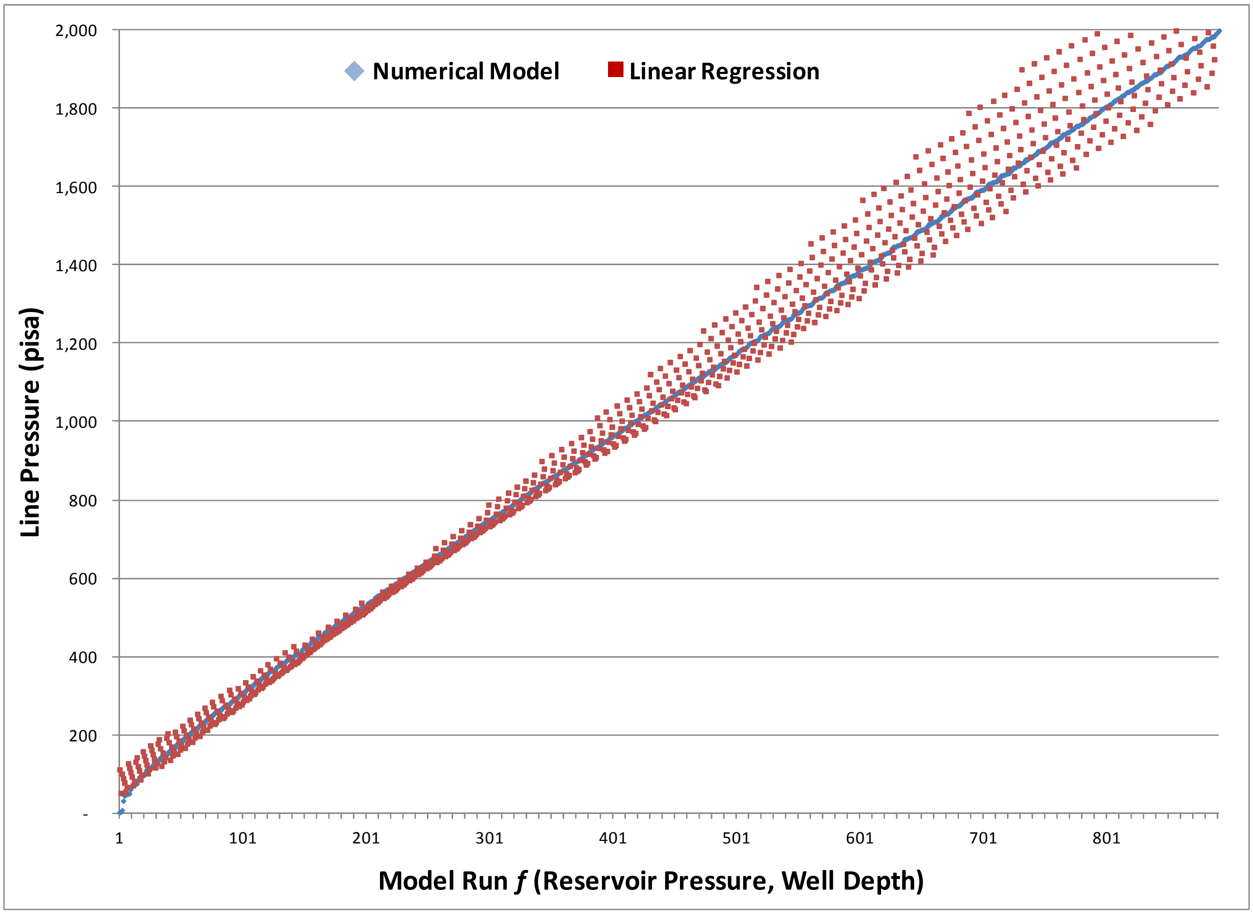


Figure 2-4 shows how for the same reservoir pressure and well depth, Equation 2-8 correlates well with the numerical model for line pressures less than 1,000 psia but has some deviation from the numerical model at line pressures greater than 1,000 psia. This analysis accepts the decrease in accuracy for line pressures above 1,000 psia because actual flow line pressures above 1,000 psia are uncommon, so that at pressures of this magnitude it is expected that flowback gas can enter most flow line systems.

Equation 2-13 indicates that when the reservoir pressure is zero and the well depth is zero the line pressure is 67.5784, which is not intended to have a physical meaning given this is a correlation rather than the model itself. A linear regression is an approximation that has inherent uncertainty in modeling the line pressure at a given depth and reservoir pressure. Therefore, since the regression is already an approximation, this analysis does not use a zero-intercept at the cost of not fitting the numerical model results the best.

2.2.5 Incorporation of Pressure Threshold Equation into the Rule

The Final NSPS OOOO Rule includes Equation 2-13 for operators to determine if they are required to combust flowback gas or perform gas capture plus combustion. Operators will input the reservoir pressure and vertical well depth for their new source gas well with hydraulic fracturing into Equation 2-13 and determine a calculated pressure of the gas immediately before it would be routed to the flow line. If the calculated line pressure is greater than the actual line pressure to be used by the operator, then the rule requires natural gas from the completion flowback to be captured in combination with combustion. If the calculated line pressure is less than or equal to the actual line pressure to be used by the operator, then the rule requires the natural gas from the completion flowback to be sent to a combustion device. The rule instructs operators to round the result of the linear equation to the nearest 10 psi to reflect the appropriate precision of the equation given how pressure settings vary within a gathering line. Rounding to the nearest 100 psia would be too coarse since gathering line pressures are typically on the order of hundreds of psia, and rounding to the nearest one psia is too precise given the sensitivity of the model.

2.3 Estimated National Impacts of Implementing the Pressure Equation

As part of the NSPS proposal rulemaking process, the EPA assessed the regulatory impacts of the proposed NSPS OOOO. This section describes the potential effect of implementing the pressure determination equation shown in Equation 2-13 to the national impacts.
To determine the impacts of implementing a pressure equation, three different investigations were carried out. The investigations differed in the methodology and data used. All investigations employed Equation 2-13 to calculate the pressure of the flowback gas as it exits the well.

For these analyses, a line pressure of 500 psia was assumed. If the calculated pressure of the well exceeded 500 psi, then the well was considered to be captured by the regulation. This assumption was used due to the lack of available gathering line pressures by producing areas in the U.S. and the understanding that such pressures typically range from 80 to 500 psia based on expert judgment. Depending on the producing area gathering line pressures will differ. The line pressure of 500 psia is therefore a conservatively high value of pressure in any field.
The three different investigations and the final conclusions drawn from the impacts estimates are listed below and discussed in the rest of this section:

2.3.1 Impacts Based on 2008 Well Completions uses characteristics of well completions from 2008 in all formations.

2.3.2 Impacts Based on All Completions from 2000 – 2010 uses characteristics of well completions from 2000 to 2010 in all formations.

2.3.3 Impacts Based on Individual Basins or Formations uses characteristics of well completions carried out in specific basins or formations.

2.3.1 Impacts Based on 2008 Well Completions

The data used for this first investigation is an output from an HPDI database query (HPDI is a data service company supplying products that aggregate U.S. production data). The query provided the total depth and the formation type (tight gas, shale, and coal bed methane) of all new gas wells in 2008 (where formation type was determined based on an assessment of each well's location and other characteristics). Using the total depth and an expert assumption of the pressure gradient per unit of distance for each formation type, the bottom-hole pressure could be estimated. Table 2-5 summarizes the pressure gradients used.

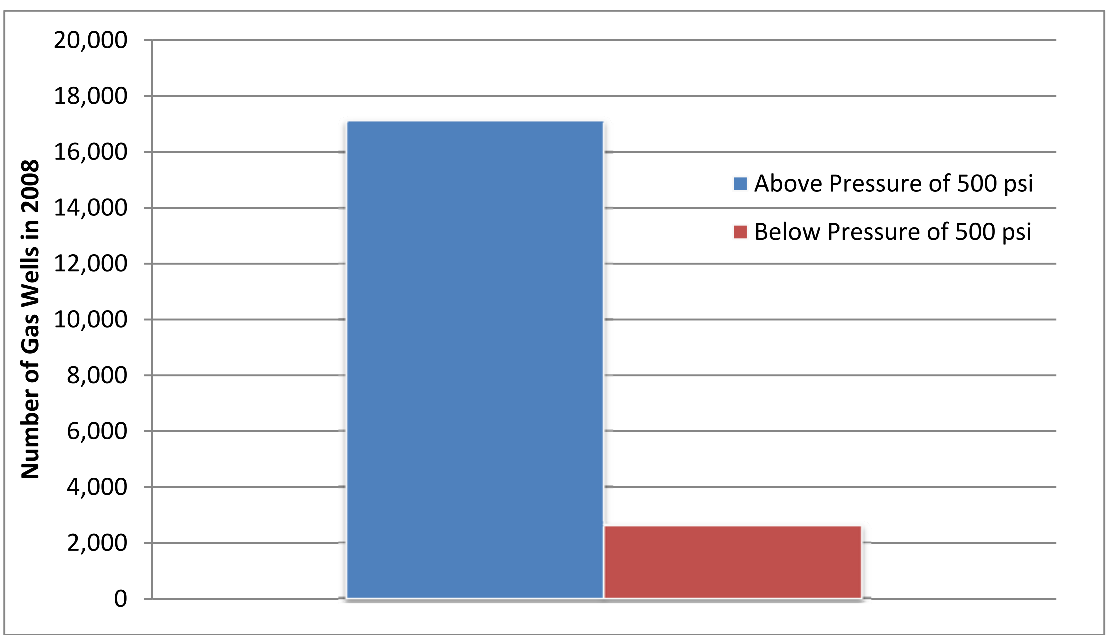
Table 2-5. Pressure Gradients for each Formation Type

Formation Type	Pressure Gradient (psi per vertical foot)
Gas Shale	0.7
Tight Gas	0.7
CBM	0.465

The bottom-hole pressure—calculated using the pressure gradients listed above—and the total depth for each new gas well in 2008 was entered into Equation 12. The resulting pressure was compared to an assumed flow line pressure of 500 psia. If the calculated pressure was greater than 500 psia, the well was considered to be capable of complying with the REC requirements of the rule.

This investigation led to the conclusion that approximately 90% of well completions would be able to overcome a flow line pressure of 500 psia. The remaining 10% had an estimated pressure below 500 psia, according to the equation and parameters used. Figure 2-5 illustrates this distribution.

Figure 2-5. Distribution of 2008 Gas Wells Above and Below the 500 psi Flow Line Pressure



This investigation did not make any distinctions for exploratory and delineation wells. It includes all new gas wells in tight, shale, and CBM formations in 2008.

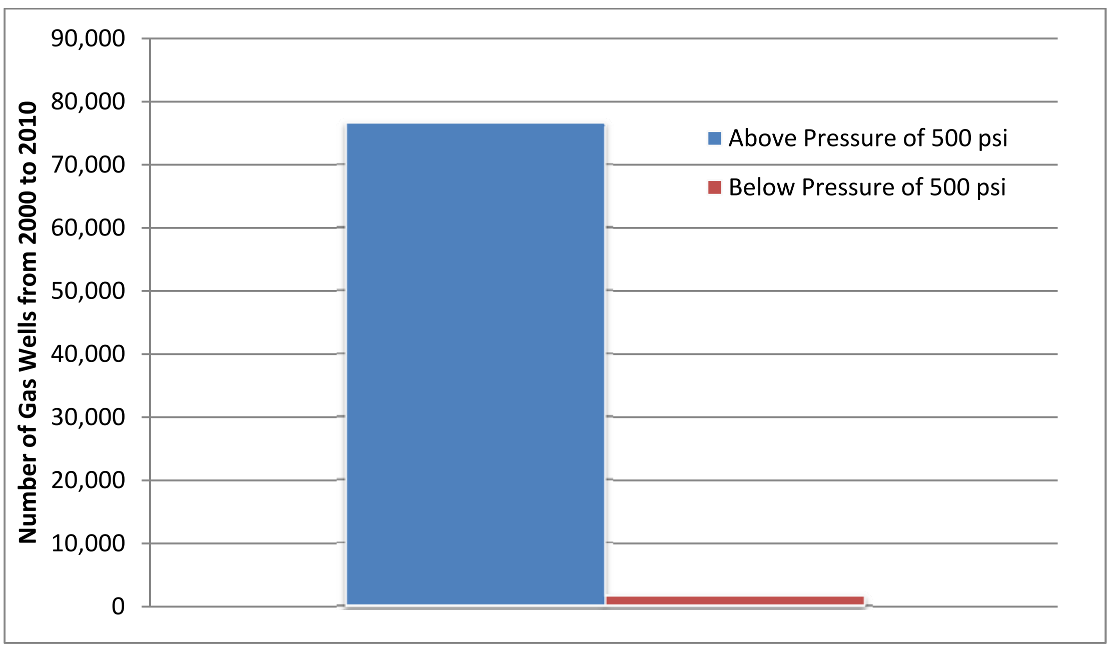
2.3.2 Impacts Based on All Completions from 2000 – 2010

The data used for this second investigation also originated from an HPDI query. The query provided the total depth and the formation type (tight gas or shale) of all gas wells that began producing from 2000 to 2010. Using the total depth and an assumption of the pressure gradient per unit of distance for each formation type as shown above in Table 2-5, the bottom-hole pressure could be estimated.

The bottom-hole pressure—calculated using the pressure gradients listed above—and the total depth for each gas well that began producing from 2000 to 2010 were entered into Equation 2-13. The resulting pressure was compared to an assumed flow line pressure of 500 psi. If the calculated pressure was greater than 500 psia, the well was considered to be capable of complying with the REC requirements of the rule.

This investigation led to the conclusion that approximately 98% of well completions would be able to overcome a flow line pressure of 500 psi. The remaining 2% had an estimated pressure below 500 psi, according to the equation and parameters used. Figure 2-6 illustrates this distribution.

Figure 2-6. Distribution of 2000 to 2010 Gas Wells Above and Below the 500 psi Flow Line Pressure



This investigation did not make any distinctions for exploratory and delineation wells. It includes all gas wells in tight and shale formations that began producing sometime between 2000 and 2010.

2.3.3 Impacts Based on Individual Basins or Formations

The data used for the third investigation originated from a variety of references including the Pennsylvania Department of Environmental Quality, the Wyoming Department of Environmental Quality, oil and gas service providers, and the Department of Energy[24]. The data collected from these references were reservoir pressures and well depths that were then inputted directly into Equation 2-13.

Several references provided a multitude of values for reservoir pressure and/or well depth. Therefore, within a given formation, this investigation paired the lower reservoir pressures with the lower depths, the average reservoir pressures with the average depths, and the higher reservoir pressures with the deeper depths to assess the impacts.
For this investigation, the selection of production areas represented by the researched data included:

- Marcellus shale
- Barnett shale
- Eagle Ford shale
- Haynesville shale
- Powder River Basin

The summary of the findings from this investigation are summarized in Table 2-6. N/A indicates that the researched data did not provide multiple values for reservoir pressure and depth.

Table 2-6. Summary of Calculated Flow Line Pressures from Individual Basins

Region	Formation Type	Bottom-Hole Pressure (psia)	Total Depth (ft)	Eq. 12 Calculated Flow Line Pressure (psia)
Marcellus *(Lower Bound)*	Gas Shale	1,700	3,000	710
Marcellus *(Average)*	Gas Shale	4,000	7,000	1,582
Marcellus *(Upper Bound)*	Gas Shale	5,760	12,000	2,175
Barnett *(Lower Bound)*	Gas Shale	2,750	5,000	1,101

[24] Table 3.4 of http://treichlerlawoffice.com/radiation/HillNY.pdf, Table 2 of http://www.sooga.org/studies/Marcellus%20Shale%20Decline%20Analysis%20-%202010%20-%20Brandon%20Baylor.pdf, http://www.transformsw.com/papers-and-presentations/studies.html#Barnett, Table A-6 (pg 212) Reservoir Pressure Profile on pg 50 (Fig 2-12) of http://www.fe.doe.gov/programs/oilgas/publications/coalbed_methane/PowderRiverBasin2.pdf, Tables 2-4 and 3-13 (Additional depths in Tables 3-3 to 3-11) of http://www.fe.doe.gov/programs/oilgas/publications/coalbed_methane/PowderRiverBasin2.pdf, page 6 of http://www.halliburton.com/public/solutions/contents/Shale/related_docs/H063771.pdf, http://www.transformsw.com/papers-and-presentations/studies.html#Eagle Ford

Barnett *(Average)*	Gas Shale	4,000	7,500	1,563
Barnett *(Upper Bound)*	Gas Shale	N/A	N/A	N/A
Eagle Ford *(Lower Bound)*	Gas Shale	N/A	N/A	N/A
Eagle Ford *(Average)*	Gas Shale	5,200	11,500	1,945
Eagle Ford *(Upper Bound)*	Gas Shale	N/A	N/A	N/A
Haynesville *(Lower Bound)*	Gas Shale	5,690	16,600	1,969
Haynesville *(Average)*	Gas Shale	8,500	12,000	3,394
Haynesville *(Upper Bound)*	Gas Shale	N/A	N/A	N/A
Powder River Basin *(Lower Bound)*	CBM	165	500	122
Powder River Basin *(Average)*	CBM	490	1,250	238
Powder River Basin *(Upper Bound)*	CBM	2,161	5,270	829

Based on the results summarized above, it is possible to draw the following conclusions:

- Most of the wells in Marcellus, Barnett, and Haynesville would be capable of overcoming a flow line pressure of 500 psia based on the pressure model developed in this section.
- The average gas wells in Eagle Ford would be capable of overcoming a flow line pressure of 500 psia based on the pressure model developed in this section.
- The average gas wells in the Powder River Basin would not be able to overcome a flow line pressure of 500 psia based on the pressure model developed in this section. Some wells in these basins would be capable of overcoming such a pressure as evidenced by the upper bound for the Powder River Basin.

2.4 Conclusions

This analysis examined the pressure drop situation for the steady flow condition of a flowback after a hydraulic fracture, for a variety of well reservoir pressures and depths. A mathematical model describing well cleanup is appropriate to describe the diversity of conditions in hydraulically fractured gas wells. This model approach accounts for the range of conditions including well depth and reservoir pressure to more accurately depict the flowback pressure immediately before the flow line. The model acknowledges that a number of factors influence the pressure of the flowback gas and represents the effects of those factors using fluid flow equations paired with the best available parameters or assumptions based on expert judgment. Other factors that may determine when to vent, combust, and/or capture are gas combustibility, fire hazards, and other field parameters, however, these were not incorporated into this model.

Given the very limited data on actual flow line pressures, the national impacts were determined based on a characteristic 500 psia flow line pressure which is expected to be a maximum value for most situations. When using available actual field data with Equation 2-13, the result was determined to be reasonable. Based on the limited research into flow line pressures, this analysis expects from a national impacts perspective that about 90 percent of annual affected facilities will be required to do gas capture in combination with combustion with provisions for venting.

3.0 GAS WELL RE-FRACTURE FREQUENCY

This section summarizes changes to the gas well refracture frequency estimates from the proposed NSPS rule to the final rule. The NSPS proposed rule estimated the number of existing natural gas wells that are fractured each year (i.e., refractured or recompleted) using an assumption from a publically available study[25] that estimated wells were refractured on average every 10 years (i.e., 10% of the total fractured gas well count is the number of gas well recompletions with hydraulic fracture in a given year). In response to comments, the EPA has reevaluated this assumption. This review included an evaluation of all comments received and other information available to EPA through the development process for the annual estimates in the Inventory of U.S. Greenhouse Emissions and Sinks.

3.1 Revised Gas Well Re-Fracture Frequency Methodology

Comments received on the proposed rule suggested that the number of wells refractured each year is less than EPA's estimates. Comments stated that the number of hydraulically fractured gas wells recompleted per year is less than EPA's estimate, ranging from 1 percent to 5 percent. No new data was provided specific to hydraulically fractured wells. One commenter cited a 1996 Gas Research Institute study[26], which the commenter stated shows a refracture rate of 2 to 3 percent. Another commenter provided records for 2008, 2009, and 2010 showing the number of producing gas wells, the number of gas well completions, and the number of gas well recompletions. In both of these cases, the data set includes both wells that were and were not hydraulically fractured, and did not distinguish between the two; therefore, it is not possible to break out the specific number of wells that were refractured.

In the evaluation of comments received, EPA consulted other data available to the Agency. This data included two sets of data provided by two separate industry representatives through the development process for annual estimates in the Inventory of U.S. Greenhouse Emissions and Sinks, and are shown below. A petroleum and natural gas industry entity (Entity X) provided the data shown in Table 3-1. Entity X provided the number of operating gas wells in all states associated with this entity except those in Alaska and Hawaii, the total number of fractured stimulation jobs per year, the number of initial stimulations completed per year, and the number of fractured stimulation jobs conducted each year on previously fractured stimulated wells (referred to in Table 3-1 as the number of workovers per year). The term *fractured stimulated workovers* was defined by Entity X as existing fractured gas wells re-stimulated with fracturing after 30 or more days of the initial fracture stimulation. Entity X averaged the number of operating gas wells and number of workovers per years from 2004 to 2010 then divided the averages to yield the re-fractured frequency per year as a percentage of the number of operating gas wells, which was 0.27%. Therefore, the average re-fracture frequency for Entity X is 0.27% ranging from 0.50% in 2006 to 0.11% in 2010.

[25] ARI/ICF (2008) *Greenhouse Gas Life-Cycle Emissions Study: Fuel Life-Cycle of U.S. Natural Gas Supplies and International LNG*. Prepared for Sempra LNG. <http://www.adv-res.com/pdf/ARI_LCA_NOV_10_08.pdf>

[26]Assessment of Technology Barriers and Potential Benefits of Restimulation R&D for Natural Gas Wells", Final Report, GRI- 96/0267, July, 1996.

Another petroleum and natural gas entity (Entity Y) submitted the data shown in Table 3-2. Entity Y provided its number of produced gas wells that have been completed with hydraulic fracturing, the number of gas wells that were re-completed using hydraulic fracturing, and the percent of unconventional gas wells recompleted with hydraulic fracturing for 2008, 2009, and 2010. The percent of unconventional gas well recompleted with hydraulic fracturing is equivalent to the percentage of gas wells that are re-fractured annually. The average re-fracture frequency for Entity Y from 2008 to 2010 is 0.61% and ranges from 0.8% in 2008 to 0.4% in 2010.

These two new data sources (submitted by Entity X and Y) and comments received on the proposed rule show a refracture frequency rate well below the 10% rate EPA used in the proposal. Based on analysis of this data and comments received, the estimate used in the final rule impacts analysis is 1%.

Table 3-1. Workover Frequency for Each Year from 2004 to 2010 from Entity X

Year	2011*	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000
Geographic area	L-48 Onshore	L-48 Onshore	L-48 Onshore	L-48 Onshore	L-48 Onshore	L-48 Onshore	L-48 Onshore	L-48 Onshore	L-48 Onshore	L-48 Onshore	L-48 Onshore	L-48 Onshore
Number of Operating Gas Wells	12,750	12,700	12,618	12,496	12,076	11,978	11,914	11,604	12,082			
Total Number of Fracture Stimulation Jobs per Year	57	258	339	556	383	365	419	424	445	429	429	235
Number of Initial Stimulations Completed each year (New Completions)	56	244	321	512	334	305	366	386	418	397	410	228
Number of Fracture Stimulation Jobs conducted each year on Previously Fracture Stimulated Wells (i.e., # of Workovers or re-fracs)	1	14	18	44	49	60	53	38	27	32	19	7

Average number of Operating Wells/yr**	12,184
Average number of re-fracs/yr**	33
Average re-frac frequency/yr percentage of operating wells**	0.27%
Total Number of re-fracs in 11.5 years	362
Total Number of wells re-fraced once	332
Total Number of wells re-fraced twice	27
Total Number of wells re-fraced three times	3

*2011 Data is current through end of June 2011

**Averages exclude 2011 partial year data

Table 3-2. Workover frequency for each year from 2008 to 2010 from Entity Y

Table 2: [redacted] Wells in Operation that Have Been Hydraulically Fractured

Year	2008	2009	2010
Producing gas wells that have been completed with hydraulic fracturing	10,640	11,510	12,000
[redacted]			
Gas wells that were recompleted using hydraulic fracturing	87	77	43
Percent of unconventional gas wells recompleted with hydraulic fracturing	0.8%	0.7%	0.4%

4.0 NATIONAL IMPACT OF NSPS OOOO REQUIREMENTS ON GAS WELL COMPLETIONS

4.1 Summary of National Impacts Methodology

This section summarizes the approach for estimating the impacts of regulating volatile organic compound (VOC) emissions from new gas well completions following hydraulic fracturing where reduced emissions completions (REC) are required. A description of the data and how it was used is provided. A similar procedure as the one shown here was used to estimate the impacts from recompletions following hydraulic fracturing and for the portion of affected facilities where combustion is used for VOC control instead of the combination of combustion and gas capture. Below is the list of steps taken to estimate each aspect of the impacts.

Estimate Emissions from Representative Individual Source

1. Develop a methane emission factor for hydraulically fractured well completions (see section 1.0 of this TSD)
2. Develop a conversion of mass of methane to mass of VOC (see separate docket memo: Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking)

Estimate Reductions from Representative Individual Source

1. Determine the control efficiency of implementing a REC (see separate docket memo: Percent of Emissions Recovered by Reduced Emission Completions, May 19, 2011)
2. Multiply the control efficiency by the VOC emissions from a representative source

Estimate the Cost of Compliance for Representative Individual Source

1. Determine average cost per day of a REC (see Section 4.4.2.3 of Proposal Technical Support Document)
2. Determine average duration of REC in days (see Section 4.4.2.3 of Proposal Technical Support Document)

Estimate the Cost-Effectiveness of VOC Control

1. Divide the reductions from a representative source by the cost for a representative source

Estimate Total Emissions from All Hydraulically Fractured Gas Well Completions

1. Estimate the number of gas well completions in a representative year
2. Multiply the number of gas well completions by the representative emissions from an individual source

Estimate Total Reductions from All Hydraulically Fractured Gas Well Completions

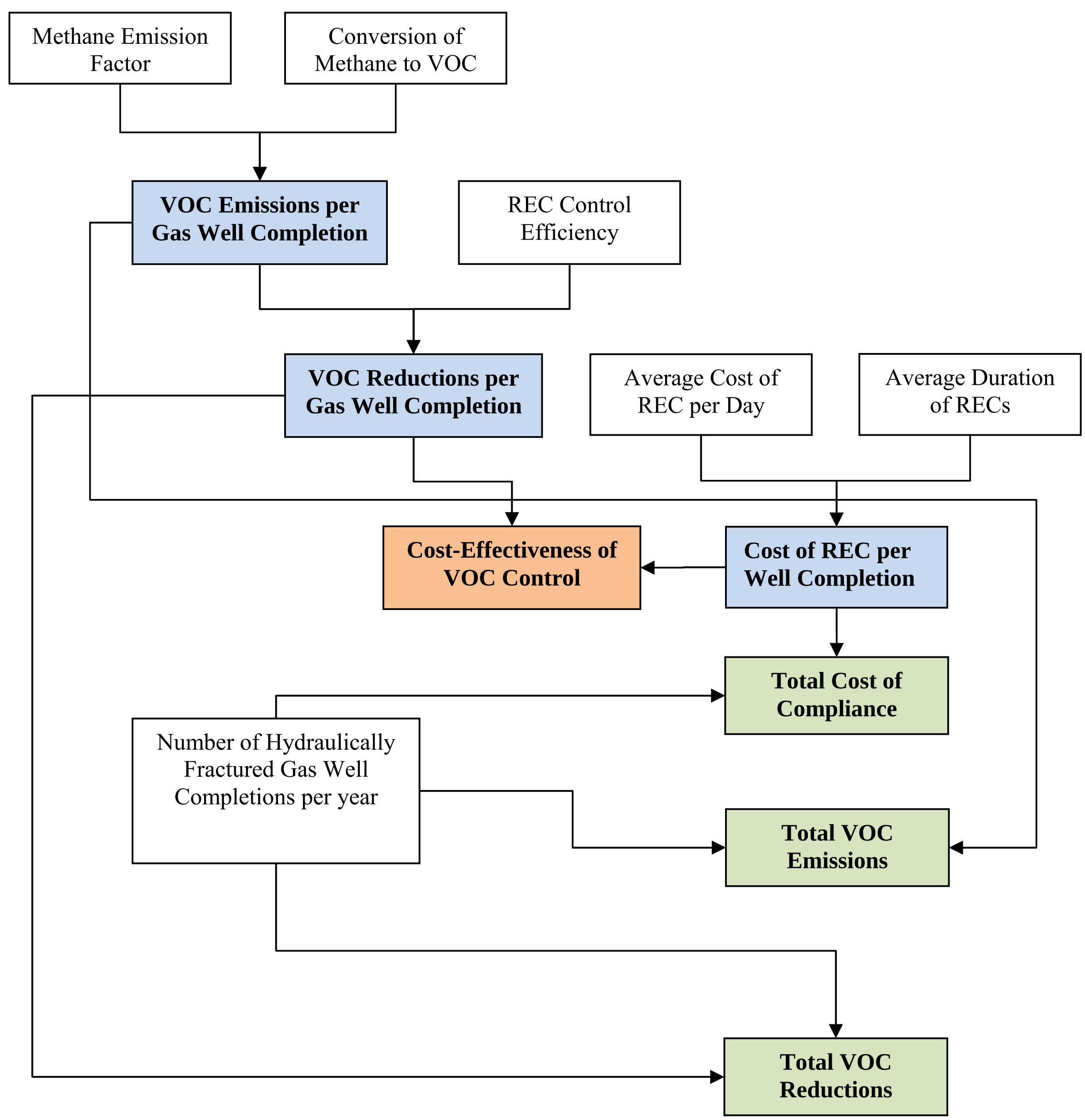
1. Estimate the number of gas well completions in a representative year
2. Multiply the number of gas well completions by the representative emissions reductions from an individual source

Estimate Total Cost of Compliance for All Hydraulically Fractured Gas Well Completions

1. Estimate the number of gas well completions in a representative year
2. Multiply the number of gas well completions by the cost of compliance for a representative individual source

Figure 4-1 illustrates the general process by which each aspect of the impacts was determined.

Figure 4-1: Flow Diagram of Impacts Estimations



4.2 Descriptions of Data Used in the Impacts Analysis

This section describes the data used for the impacts calculations. The data is also discussed in related docket memos and in the proposed TSD. The list of the data is:

- Methane emission factor for hydraulically fractured gas well completions
- Conversion of mass of methane to mass of VOC
- REC control efficiency
- Average cost of REC per day
- Revenues from natural gas product recovery
- Average duration of RECs
- Number of hydraulically fractured gas well completions per year

4.2.1 Methane Emission Factor

The emission factor for gas well completions with hydraulic fracturing was developed using four data sources, together representing data from over 1,000 well completions with hydraulic fracturing. The data included tight sands formations, shale formations, and coal bed methane (CBM) formations.

EPA evaluated both data used to develop the original factor and data received through comments in several ways to determine whether an improved emission factor could be developed. As a result of this assessment, the EPA concludes that, although it does have uncertainty, the original EPA emission factor provides a valid central estimate of emissions from this source in the U.S. Therefore, the EPA has decided to retain the data set and the methodology used to develop the original emission factor for well completions

For more information on the development of the original emission factor and the evaluation of data submitted through NSPS comments, please see the section 1 of this *Background Supplemental Technical Support Document* titled "Evaluation of the Emission Factor for Hydraulically Fractured Gas Well Completions and Recompletions."

4.2.2 Conversion of Mass of Methane to Mass of VOC

A conversion of mass of methane to mass of VOC was determined using composition data from 9 different references. Based on this data, it was possible to generate an average composition profile for produced gas, and subsequently, a ratio of mass of methane to mass of VOC.
For more information regarding the development of this ratio as well as the raw data on which it is based, please see the memo from EC/R to Bruce Moore titled "Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking".

4.2.3 REC Control Efficiency

Based on the results reported by 4 different Natural Gas STAR Partners who performed RECs, it was possible to estimate a representative control efficiency of using RECs. The companies provided both recovered and total produced gas, allowing for the calculation of the percentage of the total gas which was recovered. This estimate was based on data for more than 12,000 well completions.

4.2.4 Average Cost and Duration of RECs

The average cost and duration of RECs was obtained from data also shown in the Natural Gas STAR Lessons Learned document titled "Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells" and is available at: http://epa.gov/gasstar/documents/reduced_emissions_completions.pdf. The impacts calculations use the cost per day for gas capture and the duration of gas capture along with a setup/takedown/transport cost and a flare cost to represent the total cost. The cost is then annualized across the time horizon under study. The average cost and duration information is also covered in the TSD.

4.2.5 Revenue from Recovered Products

The costs were depicted in two different ways: without accounting for the value of the product recovered as a result of controlling VOC, and with the revenue from recovered products. To estimate the revenue from recovered products, the estimated value of the recovered gas was added to the estimated value of the recovered condensate. 90% of the gas emitted (ie 90% of the emission factor per completion event) was depicted as being captured and sold (see separate docket memo: Percent of Emissions Recovered by Reduced Emission Completions, May 19, 2011). This saved gas was multiplied by a characteristic gas price of $4 per Mcf gas. A characteristic amount of gas condensate was determined to be 34 barrels per completion, and this number of barrels was multiplied by its characteristic market value of $70 per barrel.

4.2.6 Number of Hydraulically Fractured Gas Well Completions per Year

The number of hydraulically fractured gas well completions was estimated using the National Energy Modeling System analysis consistent with the Annual Energy Outlook 2011 Reference Case. It is estimated that there would be 11,403 gas well completions in tight, shale, and CBM formations. From this total, three deductions were made:

1. The first deduction was for wildcat and delineation wells
    a. 446 well completions
    b. According to Annual Energy Outlook 2011 Reference Case
2. The second deduction was for RECs already required by state regulations
    a. 1,644 well completions
    b. 15 percent of gas well completions (after subtracting wildcat and delineation wells)
    c. Explained in Section 4.3.3 of Proposal Technical Support Document
3. The third deduction was for low pressure wells

    a. 931 well completions
    b. 10 percent of gas well completions (after subtracting wildcat and delineation gas wells and the gas well completions already controlled by state regulations)
    c. Based on the analysis conducted in Section 2.0 of this TSD
4. The fourth deduction was for completions performed with voluntary RECs
    a. 4,275 well completions
    b. 51 percent of gas well completions (after subtracting wildcat and delineation gas wells, the gas well completions already controlled by state regulations, and low pressure completions)
    c. Based on the analysis conducted in Section 5.0 of this TSD

Table 4-1 summarizes the breakdown of the estimated number of gas well completions.

Table 4-1: Number of Hydraulically Fractured Gas Well Completions

Source	Required to perform RECs not already performed voluntarily	Estimated to be performed with voluntary RECs	Required to Combust Completion Emissions*	Completions Already Regulated by States	Total Hydraulically Fractured Gas Well Completions
Hydraulically Fractured Gas Well Completion	**4,107**	**4,275**	**1,377**	**1,644**	**11,403**

* Note that the gas well completions required to combust the completion emissions are not prohibited from performing RECs. However, for the impacts assessment, these well completions are assumed to control emissions through a combustion device only.

4.3 Final Impacts Results

The Tables 4-2 through 4-4 provide the final rule impacts for well completions when REC are performed estimated using the methodologies, data, and parameters described in this section, in the docket memos, and in the TSD.

Table 4-2: Estimated Impacts per Individual Hydraulically Fractured Gas Well Completion When REC is Performed

Source	Uncontrolled VOC Emissions (tons)	VOC Emissions Reductions (tons)	Cost of Compliance (without savings)	Cost of Compliance (with savings)
Individual Hydraulically Fractured Gas Well Completion	**22.691**	**21.500**	**$33,237**	**-$1,543**

Table 4-3: Estimated Impacts for All Hydraulically Fractured Gas Well Completion When REC is Required

Source	Uncontrolled VOC Emissions (tons)	VOC Emissions Reductions (tons)	Cost of Compliance (without savings)	Cost of Compliance (with savings)
All Hydraulically Fractured Gas Well Completions	**93,198**	**88,305**	**$136,511,391**	**-$6,336,330**

Note: An additional 29,608 tons of 31,246 tons of VOC emissions are estimated to be reduced via completion combustion for hydraulically fractured gas well completions that are not required to implement a REC but are required to combust emissions.

Table 4-4: VOC Control Cost Effectiveness when a REC is Performed

Source	VOC Control Cost Effectiveness ($/ton)—without savings	VOC Control Cost Effectiveness ($/ton)—with savings
All Hydraulically Fractured Gas Well Completion	**$1,546 per ton VOC**	**-$72 per ton VOC**

5.0 VOLUNTARY REDUCTIONS FROM GAS WELL COMPLETIONS WITH HYDRAULIC FRACTURING

This section discusses an analysis which estimates the number of hydraulically fractured gas well completions performed with voluntary use of capture and combustion equipment. The analysis uses data from 2008 through 2010 and then projects that data to a 2015 basis to be consistent with the Regulatory Impacts Analysis. The analysis concludes that 51% of hydraulically fractured gas well completions and recompletions not already under state regulation and with sufficient pressure to perform a REC will implement RECs voluntarily in 2015.

The baseline emissions estimates in the proposed Regulatory Impacts Analysis for natural gas well completions and other emissions sources take into account emissions reductions conducted pursuant to state regulations covering these operations. Based on public comments and reports to the EPA's Natural Gas STAR Program, the EPA acknowledges that some producers conduct well completions using reduced emission completion (REC) techniques voluntarily. This analysis acknowledges this voluntary activity by estimating the number of hydraulically fractured gas well completions performed with voluntary use of capture and combustion equipment in 2015.

The number of hydraulically fractured gas well completions performed with voluntary use of capture and combustion equipment in 2015 is determined in the three following steps:

5.1 Number of Voluntary RECs calculates the number of gas well completions with hydraulic fracturing performed with voluntary reduction emission completion techniques in 2008, 2009, and 2010.

5.2 - Number of Completions Events Eligible for RECs calculates the number of gas well completions with hydraulic fracturing not under state regulation and with sufficient pressure to perform an REC.

5.3 - Fraction of Eligible Completions with Voluntary RECs assumes that the average fraction of gas well completions with hydraulic fracturing performed with voluntary reduction emission completion techniques in 2008, 2009, and 2010 as the fraction of gas well completions with hydraulic fracturing performed with voluntary reduction emission completion techniques in 2015.

5.1 Number of Voluntary RECs

Voluntary methane reductions from capturing and combusting methane when performing a reduced emission completion are reported by Partners and published annually in aggregate by the Natural Gas STAR Program. This analysis uses this data to estimate the number of gas well completions with hydraulic fracturing conducted using REC techniques voluntarily.

Table 5-1 shows the total methane reductions reported to the Natural Gas STAR Program from Partners performing RECs from 2008 to 2010. These figures are published annually on the

Natural Gas STAR website under the Accomplishments webpage.[27] The figures published on the Natural Gas STAR website, however, are not updated for reports received from Partners after the reported year (e.g. 2010 REC reductions reported in 2011). Table 5-1shows the most up-to-date total emission reductions reported from Natural Gas STAR Partner performing RECs including 2010 REC reductions reported in 2011.

Table 5-1. Number of Voluntary Reduced Emission Completions Performed

Year	REC iSTAR Methane Reductions (short tons/year)	Estimated Number of Voluntary RECs Performed
2008	975,905	6,600
2009	504,480	3,412
2010	590,724	3,995

The annual REC reductions shown in Table 5-1 were divided by the average methane reductions per completion, shown in Equation 5-1 to determine the number of completions with voluntary RECs, also shown in Table 5-1.

The average methane reductions per completion was determined using the emission factor for gas well completions with hydraulic fracturing, the average methane content for gas well completions, and the average reduction effectiveness for RECs. The emission factor for gas well completions with hydraulic fracturing is 9,000 Mcf. This is discussed in section 1.1.2 of this document. A memo titled *Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking*, which can be found in the rule making docket, indicates, in Table 8, that the average composition of methane in gas well completions is 83.081%. In addition, this analysis assumes that an REC reduces methane emissions from gas well completions by 95 percent. Based on an 83.081 percent methane composition, a reduction effectiveness of 95 percent, and the conversion of 48.04 thousand cubic feet per short ton, the average methane reductions per completion and recompletions is 147.86 thousand cubic feet. The calculation to determine the average methane reductions per completion is shown in Equation 5-1.

$$R = \frac{EF \times M \times C}{48.04} = 147.86 \frac{short\ tons}{completion}$$

Eq. 5-1

where,

R = average methane reductions per completion

EF = average natural gas emissions per completion (9,000 Mcf/completion)

M = average methane composition for gas well completions (83.081%)

[27] EPA. (2012) *Accomplishments.* <www.epa.gov/gasstar/accomplishments/index.html>

C = reduction effectiveness (95%)

48.04 = conversion factor 48.04 thousand cubic feet equals 1 short ton

5.2 Number of Completions Events Eligible for RECs

The historical number of gas well completions with hydraulic fracturing not required by state regulation and with sufficient pressure to perform an REC is determined using the total successful developmental and exploratory gas completions with hydraulic fracturing in 2008, 2009 and 2010, the fraction of gas well completions with hydraulic fracturing impacted by state regulation, and the fraction of low pressure completions.

5.2.1 Historical Gas Well Completions with Hydraulic Fracturing from the EIA NEMS Model

The total gas completions with hydraulic fracturing in 2008, 2009 and 2010 are determined by the National Energy Modeling System (NEMS). NEMS is a model of U.S. energy economy developed and maintained by the Energy Information Administration (EIA)[28]. 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. The NEMS database defines unconventional reservoirs as those in shale, tight sand, and coalbed methane formations and distinguishes those from wells drilled in conventional reservoirs. This analysis assumes new successful natural gas wells in shale, tight sand, and coalbed methane formations are completed with hydraulic fracturing. Table 5-2 shows the total successful developmental and exploratory gas well completions with hydraulic fracturing for 2008, 2009, and 2010. Equation 5-2 shows the number of developmental completions is the total completions less the exploratory completions.

$$DC = TC - EC \qquad \textbf{Eq. 5-2}$$

where,

DC = total developmental gas well completions with hydraulic fracturing

TC = total gas well completions with hydraulic fracturing

EC = total exploratory gas well completions with hydraulic fracturing

[28] U.S. Energy Information Administration. *Annual Energy Outlook 2011*. Energy Information Administration.

Table 5-7. Total Successful Developmental and Exploratory Gas Well Completions with Hydraulic Fracturing

Year	Total Gas Completions with Hydraulic Fracturing	Exploratory Gas Completions with Hydraulic Fracturing	Developmental Gas Completions with Hydraulic Fracturing
2008	16,862	0	16,862
2009	10,275	0	10,275
2010	9,015	312	8,703

5.2.2 Completions with Hydraulic Fracturing under State Regulation

The fraction of gas well completions and recompletions with hydraulic fracturing impacted by state regulation is determined using the analysis from the *Technical Support Document* (TSD) for the proposed NSPS OOOO rule.[29] The TSD determines fraction of gas well completions and recompletions with hydraulic fracturing impacted by state regulation accounting for regulations in Wyoming and Colorado. Since this analysis is considering historical data, when the respective Wyoming and Colorado regulations were implemented was considered. The Wyoming regulation was in place in 2008[30] and the Colorado regulation was implemented in 2009[31]. Therefore, the TSD analysis was revisited to determine the fraction of gas well completions and recompletions with hydraulic fracturing impacted by only the Wyoming regulation, for the 2008 estimate. The result was approximately 9.6 percent. This is shown in Equation 5-3, while Equation 5-4 shows that the number of developmental gas completions without hydraulic fracturing with RECs due to state regulations is determined using the 15 percent for both the WY and CO regulations, used in the 2009 and 2010 estimates.

$$DC_{noState} = DC \times (1 - 9.6\%) \qquad \textbf{Eq. 5-3}$$

$$DC_{noState} = DC \times (1 - 15\%) \qquad \textbf{Eq. 5-4}$$

where,

$DC_{NoState}$ = total developmental gas well completions with hydraulic

[29] EPA. (2011) *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Technical Support Document for Proposed Standards*. EPA-453/R-11-002. pg. 4-12

[30] State of Wyoming Department of Environmental Quality, Air Quality Division. Well Completions/Re-completions Permit Application. Page 2. August 2010. http://deq.state.wy.us/aqd/Oil%20and%20Gas/AQD-OG11_Green%20Completion%20Application.pdf

[31] Colorado Oil and Gas Conservation Commission. 2 CCR-404-1. http://oil-gas.state.co.us/RuleMaking/FinalDraftRules/COGCCFinalDraftRules_110708.pdf

fracturing not under state regulation

15% = fraction of gas well completions and recompletions with hydraulic fracturing impacted by both WY and CO state regulations

9.5% = fraction of gas well completions and recompletions with hydraulic fracturing impacted by both WY state regulations

DC = total developmental gas well completions with hydraulic fracturing

Table 5-8. Total Successful Developmental Gas Well Completions with Hydraulic Fracturing Not Under State Regulation

Year	Developmental Gas Completions with Hydraulic Fracturing	Developmental Gas Completions with Hydraulic Fracturing with RECs due to State Regulations	Developmental Gas Completions with Hydraulic Fracturing not under State Regulation
2008	16,862	1,616[a]	15,246
2009	10,275	1,554[b]	8,722
2010	8,703	1,316[b]	7,387

a. Only the Wyoming regulation is in place (9.5% of completions)
b. Both the Colorado and Wyoming regulations are in place (15% of completions)

5.2.3 Completions with Hydraulic Fracturing with Low Pressure

The fraction of gas well completions with low pressure (i.e. insufficient to capture and direct flowback gas from the well to a flow line) is 10 percent as determined in section 2.0 of this *document*. Table 5-4 shows how the total developmental gas well completions with hydraulic fracturing for 2008, 2009, and 2010 not under state regulation is used to determine the gas completions with hydraulic fracturing with sufficient pressure to perform a REC and not under state regulation in 2008, 2009, and 2010. Equation 5-5 shows how this calculation is performed.

$$DC_{NSNLP} = DC_{NoState} \times (1 - 10\%)$$

Eq. 5-5

where,

DC_{NSNLP} = historical gas completions with hydraulic fracturing with sufficient pressure perform a REC and not under state regulation

10% = fraction of gas well completions and recompletions with hydraulic fracturing impacted by state regulation

$DC_{NoState}$ = total developmental gas well completions with hydraulic fracturing not under state regulation

Table 5-9. Total Developmental Gas Well Completions with Hydraulic Fracturing with Sufficient Pressure to Perform a REC and Not Under State Regulation

Year	Developmental Gas Completions with Hydraulic Fracturing not under State Regulation	Low Pressure Gas Completions with Hydraulic Fracturing incapable of performing RECs	Total Developmental Gas Well Completions with Hydraulic Fracturing with Sufficient Pressure to Perform a REC and Not Under State Regulation
2008	15,246	1,525	13,722
2009	8,722	872	7,850
2010	7,387	739	6,648

5.2.4 Historical Completions with Hydraulic Fracturing with Sufficient Pressure to Perform a REC and not under State Regulation

Table 5-4 shows the total gas well completions with hydraulic fracturing from the EIA NEMS model is finally reduced to the gas well completions with hydraulic fracturing not under state regulation and with sufficient pressure to perform and REC in 2008, 2009, and 2010.

5.3 Fraction of Eligible Completions with Voluntary RECs

The final step in this analysis determines the percent of completions not under state regulation and with sufficient pressure to perform an REC that were conducted with voluntary REC techniques in 2015. This is done by first dividing the number of completions with voluntary RECs (from Table 5-1) by the number of historical gas completions with hydraulic fracturing with sufficient pressure to perform a REC and not under state regulation (from Table 5-4) for each year 2008, 2009, and 2010. The results of this calculation for 2008, 2009, and 2010 are shown in Table 5-5.

Table 5-5. Percent of Completions that were Conducted with Voluntary RECs

Year	Estimated Number of Voluntary RECs Performed	Total Developmental Gas Well Completions with Hydraulic Fracturing with Sufficient Pressure to Perform a REC and Not Under State Regulation	Percent of Completions not under State Regulations, with Sufficient Pressure that were Conducted with Voluntary RECs

2008	6,600	13,722	48%
2009	3,412	7,850	43%
2010	3,995	6,648	60%

Secondly, a three-year average from 2008 to 2010 was taken of the historical percentages shown in Table 5-5 to represent the variability in the implementation of voluntary RECs. The result of averaging 48%, 43%, and 60% is about 51%. The analysis and other NSPS OOOO regulation impacts analyses will assume that this 51% will be the fraction of hydraulically fractured gas well completions not already under state regulation and with sufficient pressure to perform a REC that will implement RECs voluntarily in 2015.

5.4 New Source Completions and Recompletions with Voluntary Action

The EPA estimates the number of gas completions with hydraulic fracturing with sufficient pressure to perform a REC and not under state regulation in 2015 is 8,382. Therefore, assuming 51% of these completions will perform a REC, the remaining 4,107 will constitute the completions impacted by this NSPS OOOO rule.

In addition, final TSD indicates that the number of gas recompletions with hydraulic fracturing with sufficient pressure to perform a REC and not under state regulation in 2015 is 1,085. Therefore, assuming 51% of these recompletions will perform a REC, the remaining 532 will constitute the recompletions impacted by this NSPS OOOO rule.

6.0 CENTRIFUGAL COMPRESSOR IMPACTS

This section provides additional information on parameters used in the centrifugal compressor regulatory impact analysis. This section also provides the affected facility emissions reduction estimates and cost estimates, as they have been updated in the final rule as compared to the proposed rule. Below are the parameters with significant updates along with text descriptions of those changes.

6.1 Projected Number of Affected Units

The final rule projects the number of affected units to be 13 wet seal centrifugal compressors annually. This is based on 16 new centrifugal compressor units expressed in the TSD[32] with a ratio applied to represent just wet seal units. The Inventory of Greenhouse Gas Emissions and Sinks 1990 to 2009 includes an improvement that distinguishes between wet seal vs dry seal units[33]. This data was used to create a ratio of new wet seal units versus new dry seal units. From table A-121 of the inventory annex, there were 646 wet seal compressors and 140 dry seal compressors in processing. It was decided to use this inventory ratio in lieu of the general understanding that 90% of new centrifugal compressors are dry seal[34] so that the worst-case impacts can be represented.

6.2 Capital Costs

Based on comment s received, it is evident that vapor captured from centrifugal compressor seal oil degassing is not always routed to a flare but in many cases routed back to the compressor suction or fuel system. The cost of a system of this type in which the seal oil degassing vents are routed to fuel gas, compressor suction, or an existing flare is estimated to be $22,000[35]. The estimated cost includes an intermediate pressure degassing drum, new piping, gas demister/filter, and a pressure regulator for the fuel line. Since a new flare or other combustion source is expected to be available in gas processing facilities, it was not included in the capital cost for this control option, whereas the proposed rule did include the cost of a flare. For other facilities types, the EPA estimate is that zero new affected facilities will come into existence each year[36]. Therefore the capital costs (before applying the capital recovery factor) for an affected facility in the final rule is $22,000 for seal oil degassing capture as compared to $67,918 in the proposed rule's TSD for the gas capture system and flare[37], and as compared to the proposal costs of $75,000 for use of dry seals used in the TSD[38].

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[32] Table 6-14 page 6-30 of the TSD at www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0505-0045
[33] Page A-153 of epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Annex-3.pdf Table A-121
[34] Page 6-27 of the TSD
[35] www.epa.gov/gasstar/documents/ngspartnerup_spring09.pdf
[36] Table 6-14 on page 6-30 of the TSD depicts the number of new sources per year for production and gathering & boosting to be zero each. Additionally, page 6-19 of the TSD states that new sources will be located in only the processing and transmission segments.
[37] Table 6-12 on page 6-26 of the TSD
[38] Table 6-12 on page 6-22 of the TSD

6.3 Without Revenues from Additional Product Recovery

The per unit annual cost is calculated by taking the cost of $22,000 multiplied by an annualized capital recovery factor (explained further in the TSD) of 0.1424.The total annual cost for wet seal centrifugal compressors without revenue from additional product recovery is estimated to be $40,720. This is based on a total annual cost per unit of $3,132 multiplied by 13 new units per year.

6.4 With Revenues from Additional Product Recovery

The per unit annual cost savings is calculated by taking the value of the gas that is not emitted and routed to a useful purpose as a result of the VOC control, assuming that all gas that is not emitted is being routed to a useful purpose which is reasonable given the available information on the destination of recovered seal oil degassing streams. The value of the gas is estimated as 95%[39] of the 13,186 Mcf/yr[40] of natural gas emitted per unit. The total annual cost for wet seal centrifugal compressors with revenue from additional product recovery is estimated to be -$610,657. This is based on a total annual cost per unit of -$46,974 multiplied by the 13 new units per year.

6.5 Baseline Emissions from Wet Seal Centrifugal Compressors in the Processing Sector

The baseline emissions from a representative new source are summarized in Table 6-1 based on the emissions factors and gas composition profiles in the TSD. The VOC and HAP emissions are estimated using a conversion from mass of methane to mass of VOC or HAP and a weighted average based on the assumption that 75% of centrifugal compressors in the processing segment will compress transmission quality gas.

Table 6-1. Wet Seal Centrifugal Compressor Baseline Emissions

Source	VOC (tpy)	Methane (tpy)	HAP (tpy)
Emissions per New Wet Seal Centrifugal Compressor	20.534	227.529	0.736
Total Emissions from ALL New Wet Seal Centrifugal Compressors	267	2,958	10

6.6 Emission Reduction for Wet Seal Centrifugal Compressors in the Processing Sector

The emissions reductions for wet seal centrifugal compressors in the processing sector are summarized in Table 6-2 using a 95% control efficiency.

[39] Page 6-23 of the TSD

[40] 47.7 scf methane / minute in Table 6-2 of the TSD * 43.6% annual operating factor on page 6-19 of the TSD, converted to Mcf/year and using a conversion factor of methane to natural gas of 82.9 volume percent found in the gas composition memo dated July 28, 2011.

Table 6-2. Wet Seal Centrifugal Compressor Emission Reductions – 95 Percent Control

Source	VOC (tpy)	Methane (tpy)	HAP (tpy)
Emissions Reductions Per New Wet Seal Centrifugal Compressor	19.508	216.152	0.699
Total Emissions Reductions from ALL New Wet Seal Centrifugal Compressors	253.60	2,810	9.09

7.0 UPDATE TO TECHNICAL SUPPORT DOCUMENT FOR PROPOSED STANDARDS OF PERFORMANCE FOR CRUDE OIL AND NATURAL GAS PRODUCTION, TRANSMISSION, AND DISTRIBUTION – STORAGE VESSELS

7.1 INTRODUCTION

On August 23, 2011, the U.S. Environmental Protection Agency (EPA) proposed new source performance standards (NSPS) for new sources in the crude oil and natural gas production, transmission, and distribution source category. The NSPS includes standards for storage vessels with throughput greater than 1 barrel of condensate per day (bpd) and crude oil storage vessels with throughput greater than 20 bpd of crude oil under the authority of section 111 of the Clean Air Act (CAA). The public comment period closed on November 30, 2011, and EPA received comments regarding the throughput thresholds and cost impacts of the proposed amendments to the storage vessel standards.

In response to these comments, we evaluated changes to the storage vessels new source standards. The purpose of this section is to present this analysis.

7.2 BASELINE EMISSIONS

In the technical support document (TSD) for the proposed standards,[41] we developed model tank batteries to represent the predominant population of tanks (e.g., condensate and crude oil tanks). These model tank batteries are presented in Tables 7-1 and 7-2. Using these model tanks, we developed nationwide baseline emissions (i.e., nationwide emissions in the absence of a federal rulemaking). The nationwide baseline emissions are presented in Table 7-3.

7.3 COST OF CONTROL TECHNIQUES

We evaluated two control techniques, a vapor recovery unit (VRU) and a combustor; both of which can reduce VOC emissions by 95 percent. A detailed discussion on the development of the costs associated with a VRU and a combustor is presented in the TSD.

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[41] EC/R Incorporated. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Technical Support Document for Proposed Standards. Prepared for U.S. Environmental Protection Agency. Research Triangle Park, NC. Publication No. EPA-453/R-11-0012. July 2011. Docket No. EPA-HQ-OAR-2010-0505-0045.

Table 7-1. Model Condensate Tank Batteries

	Model Condensate Tank Battery			
Parameter	**E**	**F**	**G**	**H**
Condensate throughput (bbl/day)	15	100	1,000	5,000
Condensate throughput (bbl/yr)	5,475	36,500	365,000	1,825,000
Number of fixed-roof product storage vessels				
210 barrel capacity	4	2		
500 barrel capacity		2	2	
1,000 barrel capacity			2	4
Estimated tank battery population (1992)	12,000	500	100	70
Estimated tank battery population (2008)	14,038	585	117	82
Total number of storage vessels (2008)	56,151	2,340	468	328
Percent of number of storage vessels in model condensate tank battery	94.7%	3.95%	0.789%	0.552%
Percent of throughput per model condensate tank battery	26%	7%	15%	51%
Total tank battery condensate throughput (MMbbl/yr)	32.8	9.11	18.2	63.8
Condensate throughput per model condensate battery (bbl/day)	6.41	42.7	427	2,135
Condensate throughput per storage vessel (bbl/day)	1.60	10.7	106.8	534

Minor discrepancies may be due to rounding.

[a]Model condensate tank battery development presented in the TSD for the proposed rule. (Reference 41).

Table 7-2. Model Crude Oil Tank Batteries[a]

	Model Crude Oil Tank Battery			
Parameter	**E**	**F**	**G**	**H**
Percent of number of condensate storage vessels in model size range	94.7%	3.95%	0.789%	0.552%
Number of storage vessels	491,707	20,488	4,098	2,868
Percent of throughput across condensate tank batteries	26%	7%	15%	51%
Crude oil throughput per model plant category (MMbbl/yr)	351	97.5	195	683
Crude oil throughput per storage vessel (bbl/day)	1.96	13.0	130	652

Minor discrepancies may be due to rounding.

[a] Model crude oil tank battery development presented in the TSD for the proposed rule. (Reference 41).

Table 7-3. Nationwide Baseline Emissions for Storage Vessels[a]

	Model Tank Battery				
	E	**F**	**G**	**H**	**Total**
Model Condensate Tank Batteries					
Total number of storage vessels (2008)	56,151	2,340	468	328	59,286
Total projected number of new or modified storage vessels (2015) [b]	4,630	193	39	27	4,889
Number of uncontrolled storage vessels in absence of federal regulation[c]	1,688	70	14	10	1,782
Uncontrolled VOC Emissions from storage vessel at model tank battery[d]	3.35	22.3	223	1,117	1,366
Total Nationwide Uncontrolled VOC Emissions	5,657	1,572	3,143	11,001	21,373
Model Crude Oil Tank Batteries					
Total number of storage vessels (2008)	491,707	20,488	4,098	2,868	519,161
Total projected number of new or modified storage vessels (2015) [b]	40,548	1,689	338	237	42,812
Number of uncontrolled storage vessels in absence of federal regulation[c]	14,782	616	123	86	15,607
Uncontrolled VOC Emissions from storage vessel at model tank battery[d]	0.4	2.80	28	140	171
Total Nationwide Uncontrolled VOC Emissions	6,200	1,722	3,444	12,055	23,421

Minor discrepancies may be due to rounding

[a] Nationwide baseline emissions were presented in the Technical Support Document for Proposed Standards (Reference 41)

[b]Calculated by applying the expected 8.25 percent industry growth to the number of storage vessels in 2008.

[c]Calculated by applying the estimated 36 percent of storage vessels that are uncontrolled in the absence of a Federal Regulation to the total projected number of new or modified storage vessels in 2015.

[d] VOC Emissions from individual storage vessel at model tank battery.

Cost data for a VRU was obtained from an Initial Economic Impact Analysis (EIA) prepared for the proposed State-only revisions to a Colorado regulation. [42] We assumed that the cost data in the EIA were presented in 2007 dollars. For this analysis, we escalated the costs to 2008 dollars using the Chemical Engineering (CE) Indices for 2007 (525.4) and 2008 (575.4).[43] Total capital investment was estimated to be $98,186 and is presented in Table 7-4. We estimated total annual costs to be $18,983 per year.

For combustors, we also obtained the cost data from the initial EIA prepared for State-only revisions to the Colorado regulation.42 In addition to these cost data, we added a line-item for operating labor. This is consistent with the guidelines outlined in EPA's OAQPS Control Cost Manual (OCCM) for combustion devices.[44] However, the OCCM recommends that combustion devices would require 630 hours per year of operating labor. Since we believe that most of these sites will be unmanned and would most likely be operated remotely, an estimate of 2 hours per day seems unreasonable. Therefore, we assumed that the operating labor would be more similar to that estimated for a condenser in the OCCM, 130 hours per year. We estimated a total capital investment of $32,301and a total annual cost of $19,580/yr. The costs for a combustor are presented in Table 5.

7.4 REGULATORY OPTIONS AND NATIONWIDE IMPACTS OF REGULATORY OPTIONS

7.4.1 Consideration of Regulatory Options for Condensate and Crude Oil Storage Vessels

The VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (i.e., its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid's volatility and temperature of the liquid. Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric pressure. Therefore, in order to determine the most cost effective means of controlling the storage vessels, a threshold was evaluated to limit the applicability of the standards to these storage vessels. We originally proposed the applicability threshold for storage vessel control requirements in terms of throughput because we believed that this would simplify applicability determinations for sources, particularly small sources. However, because emission factors vary widely, we now recognize that it is inappropriate to develop liquid throughput thresholds based on average emission factors.

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[42] Initial Economic Impact Analysis for Proposed State-Only Revisions to the Air Quality Control Commission's Regulation Number 7, "Emissions of Volatile Organic Compounds." September 18, 2008.

[43] Economic Indicators: Chemical Engineering Plant Cost Index. Chemical Engineering Magazine.

[44] OAQPS Control Cost Manual: Fourth Edition (EPA 450/3-90-006, January 1990). U.S. Environmental Protection Agency. Research Triangle Park, NC.

As a result, we evaluated a threshold based on VOC emissions instead of liquid throughput. We believe that the use of a VOC emissions threshold is a more flexible approach, ensuring that controls will be required only on those storage vessels where they can be applied cost-effectively. Therefore, we evaluated the costs of controlling storage vessels with varying emissions to determine which level of emissions would provide the most cost effective control option.

We evaluated an emission reduction of 95 percent, which, as discussed above, could be achieved with a VRU or a combustor. A combustor is an option for tank batteries because of the operational issues associated with a VRU. While the use of a VRU is preferable to a combustor because a combustor destroys, rather than recycles, valuable resources and there are secondary impacts associated with the use of a combustor, the cost impacts associated a combustor installed for the control of storage vessels were evaluated. This is a conservative approach, because the cost of a combustor is (slightly) higher than that of a VRU.

Table 7-4. Total Capital Investment and Total Annual Cost of a Vapor Recovery Unit

Cost Item[a]	Capital Costs ($)	Non-Recurring, One-time Costs ($)	Total Capital Investment ($)[b]	O&M Costs ($)	Savings due to Fuel Sales ($/yr)	Annualized Total Cost ($/yr)[c]
VRU	$78,000					
Freight and Design		$1,500				
VRU Installation		$10,154				
Maintenance				$8,553		
Recovered natural gas					($1,063)	
Subtotal Costs (2007)	$78,000	$11,654		$8,553	($1,063)	
Subtotal Costs (2008)[d]	$85,423	$12,763	$98,186	$9,367	($1,164)	
Annualized costs (using 7% interest, 15 year equipment life)	$9,379	$1,401		n/a	n/a	$18,983

Minor discrepancies may be due to rounding

[a] Assume cost data provided is for the year 2007. Reference 42.

[b] Total Capital Investment is the sum of the subtotal costs for capital costs and nonrecurring one-time costs.

[c] Total Annual Costs is the sum of the annualized capital and recurring costs, O&M costs, and savings due to fuel sales.

[d] Costs are escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4). Reference 43.

Table 7-5. Total Capital Investment and Total Annual Cost of a Combustor

Cost Item[a]	Capital Costs ($)	Non-Recurring, One-time Costs ($)	Total Capital Investment ($)[b]	O&M Costs ($)	Annualized Total Cost ($/yr)[c]
Combustor	$16,540				
Freight and Design		$1,500			
Combustor Installation		$6,354			
Auto Igniter	$1,500				
Surveillance System[d]	$3,600				
Pilot Fuel				$1,897	
Operating Labor[e]				$9,743	
Maintenance				$2,000	
Data Management				$1,000	
Subtotal Costs (2007)	$21,640	$7,854		$14,640	
Subtotal Costs (2008)[f]	$23,699	$8,601	$32,301	$16,033	
Annualized costs (using 7% interest, 15 year equipment life)	$2,602	$944		n/a	$19,580

Minor discrepancies may be due to rounding

[a] Assume cost data provided is for the year 2007 (Reference 42).

[b] Total Capital Investment is the sum of the subtotal costs for capital costs and nonrecurring one-time costs.

[c] Total Annual Costs is the sum of the annualized capital and non-recurring costs, O&M costs.

[d] Surveillance system identifies when pilot is not lit and attempt to relight it, documents the duration of time when the pilot is not lit, and notifies and operator that repairs are necessary.

[e] Operating labor consists of labor resources for technical operation of device (130 hr/yr), supervisory labor (15 percent of technical labor hours), and maintenance labor hours (130 hr/yr). Labor rates are $33.51/hr (for technical and maintenance labor) and $52.85 (supervisory labor) (Reference 45).

[f] Costs are escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4) (Reference 43).

[45] *Employer Costs for Employee Compensation Historical Listing March 2004 – December 2010* ftp://ftp.bls.gov/pub/special.requests/ocwc/ect/ececqrtn.pdf.

To conduct this evaluation, we considered the following four regulatory options, which are presented in Table 7-6:

- Regulatory Option 1: Control condensate storage vessels with VOC emissions greater than 3 tpy;
- Regulatory Option 2: Control condensate storage vessels with VOC emissions greater than 6 tpy;
- Regulatory Option 3: Control condensate storage vessels with VOC emissions greater than 12 tpy; and
- Regulatory Option 4: Control condensate storage vessels with VOC emissions greater than 30 tpy.

As shown in Table 7-6, Regulatory Option 1 is not cost effective for condensate storage vessels with emissions greater than 3 tpy. Therefore Regulatory Option 1 is rejected. Since the cost effectiveness associated with Regulatory Option 2 is acceptable ($3,435/ton), this option was selected. As shown in Table 7-3, Model Condensate Storage Vessel Categories F, G, and H have emissions greater than 6 tpy. Therefore, for the purposes of determining impacts, the populations of new and modified condensate storage vessels associated with categories F, G, and H are assumed to be required to reduce their emissions by 95 percent, a total of 94 new or modified condensate storage vessels by 2015.

A similar evaluation was performed for crude oil vessels and is also presented in Table 6 for the following regulatory options:

- Regulatory Option 1: Control crude oil storage vessels with emissions greater than 0.3 tpy;
- Regulatory Option 2: Control crude oil storage vessels with emissions greater than 1.5 tpy;
- Regulatory Option 3: Control crude oil storage vessels with emissions greater than 6 tpy; and
- Regulatory Option 4: Control crude oil storage vessels with emissions greater than 15 tpy.

As shown in Table 7-6, Regulatory Options 1 and 2 are not cost effective crude oil storage vessels with a emissions of 0.3 and 1.5 tpy, respectively. Therefore Regulatory Options 1 and 2 are rejected. Since the cost effectiveness associated with Regulatory Option 3 is acceptable ($3,435/ton), this option was selected. As shown in Table 3, Model Crude Oil Storage Vessel Categories G and H have emissions greater than 6 tpy. Therefore, for the purposes of determining impacts, the populations of new and modified crude oil storage vessels associated with categories G and H are assumed to be required to reduce their emissions by 95 percent, a total of 209 new or modified condensate storage vessels by 2015.

Table 7-6. Options for VOC Emissions Thresholds for Storage Vessels

Regulatory Option	VOC Emissions Threshold (tpy)	VOC Emission Reduction (tpy) [a]	Annual Costs for Combustor ($/yr) [b]	Cost Effectiveness ($/ton VOC)	Number of impacted units[c]
Condensate Storage Vessels					
1	3	2.85	$19,580	$6,870	1782
2	6	5.70	$19,580	$3,435	94
3	12	11.40	$19,580	$1,718	94
4	30	28.50	$19,580	$687	24
Crude Oil Storage Vessels					
1	0.3	0.28	$19,580	$70,584	15607
2	1.5	1.39	$19,580	$14,117	825
3	6	5.70	$19,580	$3,435	209
4	15	14.25	$19,580	$1,374	209

Minor discrepancies may be due to rounding
[a] Calculated using 95 percent reduction
[b] Refer to Table 5 for Combustor Annual Costs.
[c] Number of impacted units determined by evaluating which of the model tank batteries and storage vessel populations associated with each model tank battery (refer to Table 7-3) would be subject to each regulatory option. A storage vessel at a model tank battery was considered to be impacted by the regulatory option if its emissions were greater than the thresholds for the option.

7.4.2 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to Regulatory Option 2 for condensate storage vessels and Regulatory Option 3 for crude oil storage vessels which were selected as viable options for setting standards for storage vessels. In addition, combined impacts for a typical storage vessel are presented.

Primary Environmental Impacts of Regulatory Options

Regulatory Option 2 (condensate storage vessels) and 3 (crude oil storage vessels) were selected as options for setting standards for storage vessels as follows:

- Regulatory Option 2 (Condensate Storage Vessels): Reduce emissions from condensate storage vessels with average emissions greater than 6 tpy.

- Regulatory Option 3 (Crude Oil Storage Vessels): Reduce emissions from crude oil storage vessels with average emissions greater than 6 tpy.

Because the emissions threshold does not depend upon the type of liquid being stored in the storage vessel, the regulations will apply to all storage vessels, regardless of contents. However, for the purposes of estimating impacts, we only included populations for condensate and crude oil storage vessels. The number of storage vessels that would be subject to the regulatory options listed above are presented in Table 7-6. It was estimated that, by 2015, there would be 94 new or modified condensate storage vessels not otherwise subject to State regulations and impacted by Regulatory Option 2 (condensate storage vessels). As shown in Table 7-6, in 2015, 209 new or modified crude oil storage vessels not otherwise subject to State regulations would be impacted by Regulatory Option 3 (crude oil storage tanks).

Table 7-7 presents the nationwide emission reduction estimates for each regulatory option. Emissions reductions were estimated by applying a 95 percent control efficiency to the VOC emissions presented in Table 7-3 for each storage vessel in the model condensate and crude oil tank batteries and multiplying by the number of impacted storage vessels. For Regulatory Option 2 (condensate storage vessels), the total nationwide VOC emission reduction was estimated to be 15,061 tpy and 14,710 tpy for Regulatory Option 3 (crude oil storage vessels).

7.4.3 Nationwide Cost Impacts

Cost impacts of the individual control techniques (VRU and combustors) were presented in Tables 7-4 and 7-5. For both regulatory options, it was assumed that 50 percent of facilities would install a combustor and 50 percent a VRU. This accounts for the operational difficulties of using a VRU. Therefore, the average capital cost of control for each storage vessel was estimated to be $65,243 (the average of the total capital investment for a VRU of $98,186 and $32,301 for

Table 7-7. Nationwide Impacts of Regulatory Options

Model Tank Battery	Number of New Sources subject to Regulatory Option by 2015[a]	VOC Emissions for a Typical Storage Vessel (tpy)	Capital Cost for Typical Storage Vessel[b] ($)	Annual Cost for a Typical Storage Vessel[b] ($/yr)		Nationwide Emission Reductions (tpy)[c]		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
				Without Savings	With Savings	VOC	Methane[d]	Without Savings	With Savings	Without Savings	With Savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 2: Condensate Storage Vessels														
F	70	22.3	65,243	19,864	19,281	1,483	325	938	910	4284	4158	4.57	1.39	1.35
G	14	223	65,243	19,864	19,281	2,966	649	94	91	428	416	0.913	0.278	0.270
H	10	1117	65,243	19,864	19,281	10,612	2323	19	18	86	83	0.652	0.199	0.193
Total for Regulatory Option 2						**15,061**	**3,296**					**6.13**	**1.87**	**1.81**
Regulatory Option 3: Crude Oil Storage Vessels														
G	123	28	65,243	19,864	19,281	3,272	716	747	725	3412	3312	8.02	2.44	2.37
H	86	140	65,243	19,864	19,281	11,438	2503	149	145	682	662	5.61	1.71	1.66
Total for Regulatory Option 3						**14,710**	**3,220**					**13.6**	**4.15**	**4.03**
Combined Impacts[e]														
Typical Storage Vessel	**304**	**103**	**65,243**	**19,864**	**19,281**	**29,746**	**6,511**	**203**	**197**	**927**	**900**	**19.8**	**6.04**	**5.86**

Minor discrepancies may be due to rounding

[a] Number of storage vessels in each model tank battery (refer to Table 7-3) determined to be subject to the regulatory option as outlined in Table 7-6.

[b] It was assumed for the purposes of estimating nationwide impacts that 50 percent of facilities would install a combustor and 50 percent a VRU. This accounts for the operational difficulties of using a VRU. Capital and Annual Costs determined using the average of costs presented in Tables 7-4 and 7-5.

[c] Nationwide emission reductions calculated by applying a 95 percent emissions reduction to the VOC emissions for a typical storage vessel multiplied by the number of sources subject to the regulatory option.

[d] Methane Reductions calculated by applying the average Methane to VOC factor from the E&P Tanks Study (see Appendix A). Methane:VOC = 0.219

[e] For purposes of evaluating NSPS impact, impacts were determined for an average storage vessel by calculating total VOC emissions from all storage vessels and dividing by the total number of impacted storage vessels to obtain an average VOC emissions per storage vessel.

a combustor from Tables 7-4 and 5, respectively). Similarly, the average annual cost for a typical storage vessel was estimated to be $19,864/yr (average of the total annual cost for a VRU of $20,147/yr and $19,580/yr for a combustor from Tables 7-4 and 7-5, respectively) without including any cost savings due to fuel sales and $19,281/yr (average of the total annual cost for a VRU of $18,983/yr and $19,580/yr for a combustor from Tables 7-4 and 7-5, respectively) including cost savings.

Nationwide capital and annual costs were calculated by applying the number of storage vessels subject to the regulatory option. As shown in Table 7-7, the nationwide capital cost of Regulatory Option 2 (condensate storage vessels) was estimated to be $6.13 million and for Regulatory Option 3 (crude oil storage vessels) nationwide capital cost was estimated to be $13.6 million. Total annual costs without fuel savings were estimated to be $1.87 million/yr for Regulatory Option 2 (condensate storage vessels) and $4.15 million/yr for Regulatory Option 3 (crude oil storage vessels). Total annual costs with fuel savings were estimated to be $1.81 million/yr for Regulatory Option 2 (condensate storage vessels) and $4.03 million/yr for Regulatory Option 3 (crude oil storage vessels).

For purposes of evaluating the impact of a federal standard, impacts were determined for an average storage vessel by calculating the total VOC emissions from all storage vessels and dividing by the total number of impacted storage vessels (304) to obtain the average VOC emissions per storage vessel (103 tpy). Therefore, the nationwide annual costs were estimated to be $6.041 million/yr. A total nationwide VOC emission reduction of 29,746 tpy results in a cost effectiveness of $203/ton.

8.0 UPDATE TO TECHNICAL SUPPORT DOCUMENT FOR PROPOSED STANDARDS OF PERFORMANCE FOR CRUDE OIL AND NATURAL GAS PRODUCTION, TRANSMISSION, AND DISTRIBUTION – EQUIPMENT LEAKS

8.1 INTRODUCTION

On August 23, 2011, the U.S. Environment Protection Agency (EPA) proposed new source performance standards (NSPS) for new sources in the crude oil and natural gas production, processing, transmission, and distribution source category (40 CFR part 60, subpart OOOO). The NSPS includes standards for equipment leaks at natural gas processing plants under the authority of section 111 of the Clean Air Act (CAA). The public comment period closed on November 30, 2011, and EPA received comments on the emission reductions and cost impacts associated with equipment leaks at natural gas processing plants.

In response to these comments, we evaluated revisions to the equipment leak requirements in the proposed standards. The purpose of this memorandum is to present the results of the equipment leak cost analysis for the NSPS using emission factors and cost data from the Uniform Standards for Equipment Leaks rule (40 CFR part 65, subpart J) that EPA proposed on February 24, 2012. In addition to the emission factors and cost data, the methodology outlined in the supporting documentation for the Uniform Standards for Equipment Leaks[46] was used to estimate emission reductions for this revised analysis.

8.2 BACKGROUND

Nationwide emissions for the proposed rule were calculated using the model plant approach for estimating emissions. Baseline model plant emissions for the gas production, processing, and transmission segments were calculated using average component counts[47] for each of these segments. The emissions and emission reductions were calculated using emission factors and the control effectiveness methodology provided in the EPA equipment leak protocol[48]. Annual emissions were calculated assuming 8,760 hours of operation each year. The emissions factors were provided for total organic compounds (TOC) and included non-VOCs such as methane and ethane. The emission factors for the production and processing segments and the transmission segments that were used to estimate the new source emissions are available in Chapter 8 of the Technical Support Document[49] (TSD) for the proposed rule. Emissions for VOC, hazardous air pollutants (HAP), and methane were calculated using TOC weight fractions also available in the TSD.

[46] Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180
[47] GRI/EPA Research and Development, Methane Emissions From The Natural Gas Industry Volume 8: Equipment Leaks, June 1996. EPA-600/R-96-080h
[48] EPA, Protocol for Equipment Leak Emission Estimates, November 1995. EPA-453/R-95-017
[49] EPA, Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Technical Support Document for Proposed Standards, July 2011. EPA-HQ-OAR-2010-0505-0045

The current NSPS regulation (40 CFR part 60, subpart KKK) requires new and reconstructed natural gas processing facilities to comply with 40 CFR part 60 subpart VV standards to control emissions from equipment leaks. 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. The standards require that the facility establish a leak detection and repair (LDAR) program to limit VOC emissions from pumps in light liquid service, compressors, pressure relief valves in gas/vapor service, sampling connection systems, valves in gas/vapor and light liquid service, pumps and valves in heavy liquid service, and pressure relief devices in light liquid or heavy liquid service and connectors. These equipment leaks are detected using a detection instrument which reads the airborne concentration of volatile organic carbons at a potential leak point on a parts per million (ppm) basis. If the leak exceeds the threshold definition of the applicable regulation, repair of the leaking equipment is required. Equipment leaks also may be defined on the basis of visual observation of certain types of equipment. For most components, subpart VV defines an equipment leak as a measured instrument reading of 10,000 ppm or greater.

For the proposed subpart OOOO rule, the following regulatory options were considered for reducing equipment leaks from natural gas processing facilities:

- Regulatory Option 1: Require the implementation of a subpart VVa LDAR program;
- Regulatory Option 2: Require the implementation of a component subpart VVa LDAR program;
- Regulatory Option 3: Require the implementation of the alternative work practice in §60.18 of 40 CFR Part 60;
- Regulatory Option 4: Require the implementation of a modified alternative work practice in §60.18 of 40 CFR Part 60 that removes the requirement for annual monitoring using a Method 21 device.

Based on a review of these options in the TSD, the implementation of a subpart VVa LDAR program was determined to be the best system of emission reduction (BSER) for equipment leaks at natural gas processing plants. The cost effectiveness of this regulatory option was calculated to be $3,352 per ton of volatile organic compounds (VOC).

8.3 UNIFORM STANDARDS DATA AND METHODOLOGY

Since proposal, EPA has gathered equipment leaks data and cost information for the development of the Uniform Standards for Equipment Leaks. We believe this data represents the most up-to-date information that is available for equipment leaks from the oil and gas sector. The Uniform Standards for Equipment Leaks memorandum identifies the baseline control option as a combination of LDAR program elements, equipment design standards, and performance standards. The baseline control option is equivalent to the subpart VV LDAR program and represents the same set of requirements that apply to natural gas processing plants under 40 CFR part 60, subpart KKK.

The memorandum also provides emission factors and equipment leak frequency data for valve and connector control options. The leak frequency refers to the estimated percentage of equipment that will be found leaking at a given leak definition. The leak frequencies were used to calculate both cost and emission estimates and were estimated using several sources including the Protocol for Equipment Leak Emissions Estimates and industry data. Emission factors are the estimated leak rates of an equipment type at a given leak definition and are normally given in kg/hr/piece of equipment. Two control options from the Uniform Standards memorandum were used to evaluate the proposed subpart OOOO LDAR program. The Valve 1 Option lowers the leak definition of Valves Gas/Light Liquid to 500 ppm, and the Connectors Option 1 adds instrument monitoring for Connectors Gas/Light Liquid at 500 ppm. These valve and connector options are equivalent to a subpart VVa LDAR program and the data from these options were used to evaluate this control option. The Uniform Standards memorandum assumes that the annual monitoring would not provide any additional emissions reductions from pressure relief devices or open-ended lines.

Emission reductions were calculated from the baseline requirements. For this analysis, the leak frequency and emission factors from the Uniform Standards memorandum were used to calculate the emission reductions and costs. The Baseline data from these tables were used to calculate the subpart VV LDAR emissions and costs. The Valves Option 1 and Connectors Option 1 data were used to calculate the emissions and costs for the subpart VVa LDAR program. The initial and annual monitoring fees for each of the components were obtained from the Uniform Standards memorandum. The natural gas processing plant component counts were obtained from the GRI/EPA document[50]. A summary of the equipment leak frequencies used for this analysis are presented in Table 8-1. Tables 8-2 and 8-3 present the emission factors used for the LDAR analysis for each of the sectors. The Uniform Standards memorandum did not present an emission factor for pressure relief valves at the baseline level of control. Therefore, the pressure relief valve emission factors for subpart VV and VVa were assumed to be leaking at the rate of emissions below a 500 ppm leak definition using EPA leak rate curves.[51]

Table 8-1. Summary of Equipment Leak Frequency Percent for Model Plants

LDAR Program[a]	Valves	Connectors
Baseline	1.18/1.18	NA
Valves Option 1	5.95/1.91	NA
Connectors Option 1	NA	1.70/0.81

Data Source: Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011, Table 5.
[a] The leak frequencies provided in the tables are presented as initial leak frequency/subsequent leak frequency.

[50] GRI/EPA Research and Development, Methane Emissions From The Natural Gas Industry Volume 8: Equipment Leaks, June 1996. EPA-600/R-96-080h
[51] EPA, Protocol for Equipment Leak Emission Estimates, November 1995. EPA-453/R-95-017

Table 8-2. Summary of VOC Equipment Leak Emission Factors for Production, Gathering & Boosting and Processing Model Plants

Component	Uncontrolled (kg/comp-hr)	Baseline[a] (kg/comp-hr)	Valve Option 1[b] (kg/comp-hr)	Connector Option 1[b] (kg/comp-hr)
Valves	3.71E-04	2.24E-04	8.85E-05	NA
Connectors	1.04E-04	1.04E-04	NA	3.95E-05
Open-Ended Lines	2.30E-03	7.34E-05	NA	NA
Pressure Relief Valves	1.60E-01	9.8E-02	NA	NA

Data Source: Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011, Table 7.
[a] The baseline option is assumed to be equivalent to a subpart V/VV LDAR program.
[b] The valve and connector option 1 were assumed to be equivalent to a subpart VVa LDAR program.

Table 8-3. Summary of Methane Equipment Leak Emission Factors for Transmission and Storage Model Plants

Component	Uncontrolled[a] (Ton/comp-yr)	V/VV[b] (Ton/comp-yr)	VVa[b] (Ton/comp-yr)
Valves	0.0496	0.0300	0.0118
Connectors	0.0084	0.0084	0.0032
Open-Ended Lines	0.6408	0.0205	0.0205
Pressure Relief Valves	0.3547	0.2171	0.2171

Data Source: GRI/EPA Research and Development, Methane Emissions From The Natural Gas Industry Volume 8: Equipment Leaks, June 1996, Tables 4-17 (Transmission) and 4-24 (Storage).
[a] The uncontrolled volumetric methane emission factors were converted to a mass based emission factors assuming that methane is an ideal gas.
[b] The emission factors for the V/VV and VVa LDAR options were calculated assuming the same emission reductions in Table 2 for each of the LDAR options.

The monitoring costs for LDAR programs were based on the following assumptions:

- Initial monitoring and setup costs are $23.80 for valves, $1.10 per connector, $122 for pressure relief valve disks, $6,374 for pressure relief valve disk holder and valves, and $141 for open-ended lines.
- Subsequent monitoring costs are $1.50 for valves, $2.50 for connectors, $2.00 for pressure relief valve disks, and $5.00 for pressure relief valve devices and open-ended lines.
- A wage rate of $66.24 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on 320 hours for planning and training and 250 hours per year for reporting and administrative tasks at $92.72 per hour.
- The capital cost for purchasing a TVA or OVA monitoring system was estimated to be $10,800 and $14,500 for a data collection system.

8.3 RESULTS

In the proposed rule, it was determined that only processing plants were cost effective to control emissions of VOC. However, since a new methodology was being used to calculate emission reductions from processing plants, we decided to re-evaluate the LDAR options for each of the oil and natural gas segments. The production, gathering and boosting, transmission and storage segments were evaluated for the subpart VV and subpart VVa options from their current uncontrolled baseline.

Table 8-4 provides a summary of the VOC cost effectiveness of going from uncontrolled emission level to a subpart VV or subpart VVa LDAR program for the production, gathering and boosting, transmission, and storage segments. For processing plants the table provides the incremental cost effectiveness of going from a subpart VV to a subpart VVa LDAR program. The average VOC cost effectiveness of the production pads were calculated to be $7,964 per ton of VOC reduced for the subpart VV LDAR option and $7,379 per ton of VOC reduced for the subpart VVa LDAR option. For gathering and boosting stations, the average VOC cost effectiveness were calculated to be $4,265 per ton of VOC reduced for the subpart VV LDAR option and $4,131 per ton of VOC reduced for the subpart VVa LDAR option. The average VOC cost effectiveness of the transmission and storage segments were calculated to be $112,127 and $27,201 per ton of VOC reduced, respectively, for the subpart VV LDAR option and $57,144 and 23,819 per ton of VOC reduced, respectively, for the subpart VVa LDAR option.

The incremental VOC cost effectiveness for processing plants was calculated to be $2,691 per ton of VOC reduced. The incremental emission reductions from going from a subpart VV to a subpart VVa LDAR program is estimated to be 4.56 tons per year of VOC. In addition, 0.172 tons per year of HAP, and 16.4 tons per year of methane will also be removed. Appendix C provides a summary of the emissions calculations using the subpart VV and VVa emission factors from the Uniform Standards document, and a summary of the capital and annual costs of implementing the subpart VV and subpart VVa LDAR programs using cost data from the Uniform Standards memorandum. These results will be used to calculate the regulatory impacts of requiring a subpart VVa LDAR program in the final subpart OOOO rule.

Table 8-4. Summary of VOC Cost Effectiveness of the LDAR Options for each of the Oil and Natural Gas Segments

LDAR Option	Total Capital Investment	Annual LDAR Cost ($/yr)	VOC Emission Reduction (Ton/yr)	VOC Cost Effectiveness ($/Ton of VOC)
Well Pads				
V/VV	$101,100	$55,365	6.95	$7,964
VVa	$102,543	$57,534	7.80	$7,379
Gathering & Boosting				
V/VV	$374,334	$135,821	31.8	$4,265
VVa	$379,571	$143,807	34.8	$4,131
Processing[a]				
VVa	$8,041	$12,261	4.56	$2,691
Transmission				
V/VV	$151,669	$78,728	0.702	$112,127
VVa	$156,332	$85,601	1.50	$57,144
Storage				
V/VV	$571,841	$206,513	7.59	$27,201
VVa	$582,574	$222,970	9.36	$23,819

[a] Processing plants are already required to do a subpart VV LDAR program under subpart KKK. The costs and emissions from this sector are the incremental costs from going from a subpart VV to a subpart VVa LDAR program.

United States Environmental Protection Agency

Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

Background Supplemental Technical Support Document for the Final New Source Performance Standards

Appendices

APPENDIX A: SUPPLEMENTARY DATA FOR THE EVALUTION OF THE EMISSION FACTOR FOR HYDRAULICALLY FRACTURED GAS WELL COMPLETIONS AND RECOMPLETIONS

A.1 Industry Data Set #1

This section contains Industry Data Set #1. This data set includes vertical gas wells drilled before 2004, that were in tight sand and hydraulically fractured and were used to assist in development of the Reduced Emissions Completions Lessons Learned study. This data set was used in developing the first depiction of national methane emissions potential from hydraulic fracturing completion, presented in a Gas STAR workshop September 21, 2004.

The data set is provided in the below table. Each row contains one well completion at a well with hydraulic fracture. The columns report the total gas flared during the completion event, the total gas sold (recovered by reduced emissions completion methods into the flow line), and the sum of the flared and sold volumes which represents the total gas produced by the well during the completion event.

At the bottom of the table are the sums for the total completions, total gas flared, total gas sold, and total gas produced. The sums are then used to calculate an average emissions factor.

Well Completion Number	Flared Gas (Mcf)	Gas Sold (Mcf)	TOTAL Mcf PRODUCED PER COMPLETION
1	878	6,919	7,797
2	3,293	8,638	11,931
3	3,348	2,386	5,734
4	1,670	2,339	4,009
5	7,095	800	7,895
6	2,884	11,549	14,433
7	1,553	4,503	6,056
8	4,005	169	4,174
9	6,614	363	6,977
10	2,536	3,377	5,913
11	2,043	5,203	7,246
12	1,010	3,792	4,802
13	3,586	149	3,735
14	12,659	4,692	17,351
15	4,307	970	5,277
16	4,053	1,105	5,158
17	3,987	12,058	16,045
18	1,320	964	2,284
19	1,576	2,133	3,709
20	2,752	3,903	6,655
21	4,063	2,629	6,692
22	5,591	12,652	18,243

23	2,550	3,696	6,246
24	1,057	7,429	8,486
25	2,206	9,085	11,291
26	1,274	6,832	8,106
27	4,333	6,558	10,891
28	4,626	941	5,567
29	1,091	23	1,114
30	861	278	1,139
31	324	7	331
32	774	1,197	1,971
33	1,503	4,489	5,992
34	6,525	7,398	13,923
35	1,125	2,027	3,152
36	1,894	1,723	3,617
37	1,398	4,876	6,274
38	2,104	11,331	13,435
39	1,149	3,641	4,790
40	803	420	1,223
41	2,619	445	3,064
42	889	2,532	3,421
43	153	0	153
44	1,749	3,986	5,735
45	1,450	1,248	2,698
46	807	277	1,084
47	1,833	0	1,833
48	1,577	3,508	5,085
49	1,219	1,552	2,771
50	1,557	4,444	6,001
51	1,880	5,795	7,675
52	2,501	4,096	6,597
53	5,698	211	5,909
54	2,355	1,922	4,277
55	971	2,034	3,005
56	6,213	159	6,372
57	2,599	2,592	5,191
58	1,502	8,212	9,714
59	2,219	931	3,150
60	6,114	1,925	8,039
61	1,020	740	1,760
62	594	2,727	3,321
63	2,189	5,840	8,029
64	1,350	1,528	2,878
65	0	0	0
66	2,674	3,872	6,546
67	2,424	3,352	5,776
68	941	3,639	4,580

69	1,126	4,683	5,809
70	1,264	2,117	3,381
71	1,833	1,953	3,786
72	1,513	4,940	6,453
73	9,157	9,568	18,725
74	3,026	7,770	10,796
75	3,026	501	3,527
76	16,849	5,802	22,651
77	1,768	2,137	3,905
78	9,234	1,027	10,261
79	2,191	4,017	6,208
80	0	0	0
81	5,300	1,260	6,560
82	1,694	2,022	3,716
83	673	1,234	1,907
84	313	2,651	2,964
85	0	0	0
86	3,883	5,211	9,094
87	1,800	4,296	6,096
88	1,468	3,237	4,705
89	2,946	8,984	11,930
90	1,059	1,715	2,774
91	2,381	5,754	8,135
92	882	658	1,540
93	255	1,933	2,188
94	742	2,356	3,098
95	889	0	889
96	844	3,606	4,450
97	1,052	2,863	3,915
98	1,006	581	1,587
99	502	723	1,225
100	3,470	3,079	6,549
101	2,529	5,688	8,217
102	4,725	3,283	8,008
103	523	1,203	1,726
104	2,469	5,548	8,017
105	602	1,571	2,173
106	812	4,782	5,594

Total Well Completions	**Total Flared Gas (Mcf)**	**Total Gas Sold (Mcf)**	**Total Produced Gas (Mcf)**
106	**267,323**	**349,564**	**616,887**

<u>EF Calculation:</u>

$$\frac{616{,}887\,Mcf}{106\,completions} = 5{,}820\,\frac{Mcf}{completion}$$

APPENDIX B: SUPPLEMENTARY ANALYSES FOR LOW PRESSURE COMPLETION THRESHOLD

B.1 Derivation of Density from the Ideal Gas Law

This appendix shows how this analysis determines the density of natural gas as a function of the temperature and pressure using the ideal gas law.

Ideal Gas Law

$$\boxed{PV = nRT} \qquad \textbf{(Eq. B.1-1)}$$

Step 1 – Multiply both side by the molecular weight *MW*

$$\boxed{(MW)PV = nRT(MW)} \qquad \textbf{(Eq. B.1-2)}$$

Step 2 – Divide both sides by the volume

$$\boxed{\frac{(MW)PV}{V} = \frac{nRT(MW)}{V}} \qquad \textbf{(Eq. B.1-3)}$$

Step 3 – The volumes on the left hand side cancel.

$$\boxed{P(MW) = \frac{nRT(MW)}{V}} \qquad \textbf{(Eq. B.1-4)}$$

Step 4 – Knowing $n(MW)$ is equal to the mass of the ideal gas, substitute m for $n(MW)$

$$\boxed{P(MW) = \frac{mRT}{V}} \qquad \textbf{(Eq. B.1-5)}$$

Step 5 – Knowing m/V is equal to the density of ideal gas, substitute ρ for m/V

$$\boxed{P(MW) = \rho RT} \qquad \textbf{(Eq. B.1-6)}$$

Step 6 – Solve for ρ

$$\boxed{\rho = \frac{P(MW)}{RT}} \qquad \textbf{(Eq. B.1-7)}$$

Nomenclature

P	=	pressure of the ideal gas (Pa)
V	=	volume of the ideal gas (m^3)
R	=	ideal gas constant, 8.314 $m^3 Pa\ mol^{-1} K^{-1}$

T	=	temperature of the ideal gas (K)
n	=	moles of the ideal gas (moles)
m	=	mass of the ideal gas (g)
MW	=	molecular weight of the ideal gas (g/mol)
ρ	=	density of the ideal gas (g/m^3)

B.2 Water Film Impact on Inner Tubing Diameter

This appendix shows the steps taken to determine the extent to which water plated on the tubing wall restricts the cross sectional area of the tubing that is available for gas flow. The purpose of the appendix is to show that the restriction in cross sectional area is negligible, which in turn has a negligible effect on the change in flow velocity. The appendix calculates the thickness of a film of water deposited along the walls of a well tubing based on the percent of water by volume in the tubing. Since water is expected to adhere to the walls of the tubing, this analysis assumes that the largest film thickness occurs where all the water in the tubing is plating on the inner tubing wall rather than remaining in the bulk flow. The following equations determine the thickness of this film of water on the inner tubing wall.

Step 1a	$V_T = V_W + V_G$	**(Eq. B.2-1a)**
Step 1b	$f_L = \frac{V_W}{V_T} = \frac{V_W}{V_W + V_G}$	**(Eq. B.2-1b)**
Step 1c	$V_W = \frac{f_L V_G}{1 - f_L}$	**(Eq. B.2-1c)**
Step 2	$V_T = \left(\frac{f_L}{1 - f_L}\right) V_G + V_G$	**(Eq. B.2-2)**
Step 3	$\frac{\pi {D_T}^2}{4} = \left(1 + \frac{f_L}{1 - f_L}\right) \frac{\pi {D_G}^2}{4}$	**(Eq. B.2-3)**
Step 4	${D_T}^2 = \left(\frac{1}{1 - f_L}\right) {D_G}^2$	**(Eq. B.2-4)**
Step 5	$D_G = \sqrt{{D_T}^2 (1 - f_L)}$	**(Eq. B.2-5)**
Step 6	$\delta_{water} = \frac{D_T - D_G}{2}$	**(Eq. B.2-6)**
Step 7	$\delta_{water} = \frac{D_T - \sqrt{{D_T}^2 (1 - f_L)}}{2}$	**(Eq. B.2-7)**
Step 8	$\delta_{water} = \frac{2.875 - \sqrt{2.875^2 (1 - 0.05)}}{2} = 0.036\ in.$	**(Eq. B.2-8)**

Step 9	$\frac{2\delta_{water}}{D_T} \times 100 = 2.5\%$	**(Eq. B.2-9)**

According to the result from Step 8, given the volume of water in the tubing is 5 percent of the total volume the thickness of the film of water is about 0.035 inches. Therefore, as shown in Step 9, above, the percent of the inner tubing diameter that is displaced by the film of water is about 2.5%.

Nomenclature

V_W = total volume of water in tubing, cubic inches
V_G = total volume of gas in tubing, cubic inches
V_T = total volume of tubing, cubic inches
D_T = inner diameter of the tubing, in inches
D_G = diameter of the gas in tubing, in inches
f_L = fraction of water-sand mixture in fluid, by volume, in flowback fluid, unitless
δ_{water} = thickness of water film along tubing wall, in inches

B.3 Determination of Turbulent Flow

This analysis assumes that gas wells are in turbulent flow during steady vapor flow condition of a flowback following a hydraulic fracture. The Reynolds number is defined as the ratio of fluid momentum force to viscous shear force and shown in Equation C-1 below. The Reynolds number can be used as a parameter to distinguish between laminar and turbulent fluid flow.

$$N_{Re} = \frac{Du\rho}{\mu} \qquad \textbf{(Eq. B.3-1)}$$

where,

N_{Re} = Reynolds Number

D = inner diameter of tubing, in meters

ρ = fluid density, in kilograms per cubic meter

μ = fluid viscosity, Pascal-seconds

The change from laminar to turbulent flow occurs at a Reynolds numbers around 2,100 for flow in a circular pipe. By inspection of a friction factor versus Reynolds number diagram[52], for circular pipes, the Reynolds number needs to be above 10^4 for the flow to be in the turbulent regime.

To prove the Reynolds number falls in the turbulent regime for most gas wells, the Reynolds number was calculated for a range of flowing pressures and velocities assuming a conservatively constant diameter and gas viscosity. Appendix B.1 shows that the gas density is calculated as a function of the molecular weight, temperature, pressure, and the compressibility factor. Therefore, the density is calculated assuming the temperature of the gas is 200 °F, the molecular weight is 0.016 kilograms per mole, and calculating the compressibility factor using the Brill-Beggs correlation. The gas viscosity is also a function of the pressure and temperature, and it is calculated using the Carr, Kobayashi, and Burrows correlation from the *Natural Gas Engineering Handbook*[53]. The tubing diameter was assumed to be 2.875 inches, which is equal to 0.073 meters. The resulting Reynolds numbers are shown in Table B.3-1 below. The pressures and velocities in Table B.3-1 were selected because they fall within a range of the conditions experienced by gas wells during hydraulic completion flowback.

Table B.3-1. Reynolds Numbers for Various Gas Velocities and Pressures

P (psia)	*u (ft/s)*	N_{Re}
500	10	3.043E+05
1000	20	1.174E+06
1500	10	8.463E+05
2000	20	2.159E+06
2500	10	1.284E+06

[52] Perry, R.H. (1963). *Perry's Chemical Engineers' Handbook* (4th Edition). McGraw-Hill. pg. 5-20.
[53] Guo, B. Ghalambor, A. (2005) Natural Gas Engineering Handbook.Gulf Publishing Company. pg. 17

3000	20	2.913E+06
3500	10	1.596E+06
4000	20	3.410E+06
4500	10	1.784E+06
5000	20	3.675E+06

All the Reynolds numbers in Table B.3-1 are well above the region for laminar flow indicating that for natural gas pressures and velocities common in gas wells turbulent flow is most often the case.

B.4 Alternative Method for Calculating the Compressibility Factor for Natural Gas

For further comparison, this appendix tests the accuracy of the Brill-Beggs correlation chosen for this pressure model using another method to estimate the compressibility factor. This method uses a correlation developed by Pitzer and others[54] for the second virial coefficient B in a common form of the truncated equation of state shown below:

$$Z = 1 + \frac{BP}{RT} = 1 + \dot{B}\frac{P_r}{T_r} \qquad \textbf{(Eq. B.4-1)}$$

Where $\dot{B}$ is a reduced second virial coefficient given by $\dot{B} = BP_c/RT_c$. Pitzer proposed a correlation to yield values for $\dot{B}$:

$$\dot{B} = B^0 + wB^1 \qquad \textbf{(Eq. B.4-2)}$$

B^0 and B^1 are approximate values that are functions of reduced temperature only. Therefore, by combining Equations D-1 and D-2 above, the equation used to estimate the compressibility factor for comparison to Brill-Beggs was:

$$Z = 1 + B^0\frac{P_r}{T_r} + wB^1\frac{P_r}{T_r} \qquad \textbf{(Eq. B.4-3)}$$

where:

$$B^0 = 0.083 - \frac{0.422}{T_r^{1.6}} \qquad \textbf{(Eq. B.4-4)}$$

$$B^1 = 0.139 - \frac{0.172}{T_r^{4.2}} \qquad \textbf{(Eq. B.4-5)}$$

The equations for B^0 and B^1, along with the accentric factor w, represent an approximation of the reduced second virial coefficient $\dot{B}$. Using the reduced temperature (which was assumed constant throughout the well), reduced pressure (calculated incrementally using the pressure at each well depth), and the accentric factor for methane, a compressibility factor was calculated for each segment of the vertical well. This allowed for a side-by-side comparison of the compressibility factor at each well depth using both the Brill-Beggs method and Pitzer correlation. The two methods showed agreement for lower pressures between 500 and 2000 pound per square inch. Table D-1 below compares the compressibility factors for the Brill-Beggs correlation used in this analysis and the Pitzer compressibility factor correlation.

Table B.4-1. Compressibility Factor for Various Pressures at 200°F

P (psia)	**Compressibility Factor (Brill-Beggs)**	**Compressibility Factor (Pitzer)**
500	0.98	0.98
1000	0.96	0.96
1500	0.95	0.94

[54] J.M. Smith, H.C. Van Ness, M.M. Abbott. (2005). *Introduction to Chemical Engineering Thermodynamics*. McGraw-Hill.

2000	0.94	0.92
2500	0.94	0.90
3000	0.94	0.87
3500	0.95	0.85
4000	0.96	0.83
4500	0.98	0.81
5000	1.01	0.79

The Pitzer correlation for the second virial coefficient was chosen because of its relative simplicity as a quick method to validate the calculations of the more involved Brill-Beggs method. However, it is worth noting that this correlation only estimates the properties of pure gases. Thus, pure methane was assumed in this analysis because natural gas primarily consists of methane. In addition, this simplest form of the virial equation has validity at low to moderate pressures where the compressibility factor is linear in pressure, which explains the increase in disagreement between the compressibility factors at higher pressures.

APPENDIX C: COST AND EMISSION SPREADSHEETS OF THE LDAR ANALYSES

The tables in this appendix provide a summary of the emissions calculations using the subpart VV and VVa emission factors from the Uniform Standards document, and a summary of the capital and annual costs of implementing the subpart VV and subpart VVa LDAR programs using cost data from the Uniform Standards memorandum.

Summary of Cost Effectiveness of the Subpart VV and Subpart VVa LDAR Programs for Well Pads

Average Model Plant Cost Effectiveness Summary for Well Pads w/o Recovery Credits

Model Plant	Total Capital Investment	Annual LDAR Cost ($/yr)	Recovery Credits ($/yr)[1]	Annual LDAR Cost w/o Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions	VOC Cost Effectiveness ($/Ton)	Total HAP Emissions (Tons/yr)	Total HAP Emission Reductions	HAP Cost Effectiveness ($/Ton)
Model Plant 1 (Based on 1-Wellhead)													
Baseline	-----	-----		-----	0.330	-----	-----	0.0916	-----	-----	0.00345	-----	-----
V/VV	$25,704	$32,169		$32,169	0.206	0.123	$260,914	0.0573	0.0343	$938,538	0.00216	0.00129	$24,894,909
VVa	$25,762	$32,258		$32,258	0.0810	0.249	$129,786	0.0225	0.0691	$466,856	0.000849	0.00260	$12,383,448
Model Plant 2 (Based on 5 Wellheads)													
Baseline	-----	-----		-----	64.04	-----	-----	17.80	-----	-----	0.671	-----	-----
V/VV	$101,100	$55,365		$55,365	39.03	25.01	$2,214	10.85	6.95	$7,964	0.409	0.262	$211,253
VVa	$102,543	$57,534		$57,534	35.99	28.05	$2,051	10.01	7.80	$7,379	0.377	0.294	$195,736
Model Plant 3 (Based on 48 Wellheads)													
Baseline	-----	-----		-----	672	-----	-----	187	-----	-----	7.04	-----	-----
V/VV	$820,109	$278,139		$278,139	410	262.1	$1,061	114	72.86	$3,818	4.29	2.75	$101,264
VVa	$835,227	$300,812		$300,812	378	294.0	$1,023	105	81.7	$3,681	3.96	3.08	$97,637

[1] Annual LDAR includes no recovery credits.

Average Model Plant Cost Effectiveness Summary for Well Pads w/ Recovery Credits

Model Plant	Total Capital Investment	Annual LDAR Cost ($/yr)	Recovery Credits ($/yr)[1]	Annual LDAR Cost w/ Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions	VOC Cost Effectiveness ($/Ton)	Total HAP Emissions (Tons/yr)	Total HAP Emission Reductions	HAP Cost Effectiveness ($/Ton)
Model Plant 1 (Based on 1-Wellhead)													
Baseline	-----	-----	-----	-----	0.330	-----	-----	0.0916	-----	-----	0.00345	-----	-----
V/VV	$25,704	$32,169	$29	$32,141	0.206	0.123	$260,682	0.0573	0.0343	$937,704	0.00216	0.00129	$24,872,791
VVa	$25,762	$32,258	$58	$32,201	0.0810	0.249	$129,554	0.0225	0.0691	$466,022	0.000849	0.00260	$12,361,331
Model Plant 2 (Based on 5 Wellheads)													
Baseline	-----	-----	-----	-----	64.04	-----	-----	17.80	-----	-----	0.671	-----	-----
V/VV	$101,100	$55,365	$5,797	$49,569	39.03	25.01	$1,982	10.85	6.952	$7,130	0.409	0.2621	$189,135
VVa	$102,543	$57,534	$6,501	$51,033	35.99	28.05	$1,820	10.01	7.797	$6,545	0.377	0.2939	$173,618
Model Plant 3 (Based on 48 Wellheads)													
Baseline	-----	-----	-----	-----	672	-----	-----	187	-----	-----	7.04	-----	-----
V/VV	$820,109	$278,139	$60,750	$217,388	410	262.1	$830	114	72.86	$2,984	4.29	2.747	$79,146
VVa	$835,227	$300,812	$68,143	$232,669	378	294.0	$791	105	81.7	$2,847	3.96	3.081	$75,519

[1] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $4/Mscf.

Well Pad Emission Summary

Model Plant 1 - Single Wellhead

	Model Plant Component Count				VOC Emissions (Tons/yr)						HAP Emissions (Tons/yr)					
Monitoring	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total VOC Emissions	Emission reduction	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total HAP Emissions	Emission reduction
Uncontrolled	9	37	1	0	0.032	0.037	0.022	0.000	0.092		0.001	0.001	0.001	0.000	0.003	
V	9	37	1	0	0.019	0.037	0.001	0.000	0.057	0.034	0.001	0.001	0.000	0.000	0.002	0.001
VV	9	37	1	0	0.019	0.037	0.001	0.000	0.057	0.034	0.001	0.001	0.000	0.000	0.002	0.001
VVa	9	37	1	0	0.008	0.014	0.001	0.000	0.023	0.069	0.000	0.001	0.000	0.000	0.001	0.003

Model Plant 2 - Five Wellheads

	Model Plant Component Count				VOC Emissions (Tons/yr)						HAP Emissions (Tons/yr)					
Monitoring	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total VOC Emissions	Emission reduction	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total HAP Emissions	Emission reduction
Uncontrolled	235	863	29	10	0.842	0.867	0.644	15.450	17.803		0.032	0.033	0.024	0.582	0.671	
V	235	863	29	10	0.508	0.867	0.021	9.455	10.851	6.952	1.92E-02	3.27E-02	7.75E-04	3.56E-01	4.09E-01	0.262
VV	235	863	29	10	0.508	0.867	0.021	9.455	10.851	6.952	1.92E-02	3.27E-02	7.75E-04	3.56E-01	4.09E-01	0.262
VVa	235	863	29	10	0.201	0.329	0.021	9.455	10.006	7.797	7.57E-03	1.24E-02	7.75E-04	3.56E-01	3.77E-01	0.294

Model Plant 3

	Model Plant Component Count				VOC Emissions (Tons/yr)						HAP Emissions (Tons/yr)					
Monitoring	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total VOC Emissions	Emission reduction	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total HAP Emissions	Emission reduction
Uncontrolled	2,454	9,080	299	105	8.791	9.119	6.641	162.226	186.776		0.331	0.344	0.250	6.116	7.041	
V	2,454	9,080	299	105	5.308	9.119	0.212	99.282	113.921	72.856	0.200	0.344	0.008	3.743	4.295	2.747
VV	2,454	9,080	299	105	5.308	9.119	0.212	99.282	113.921	72.856	0.200	0.344	0.008	3.743	4.295	2.747
VVa	2,454	9,080	299	105	2.097	3.463	0.212	99.282	105.055	81.722	0.079	0.131	0.008	3.743	3.961	3.081

VOC Emission Factors

	Uncontrolled (kg/hr/comp)	V _ VV (kg/hr/comp)	VVa (kg/hr/comp)
Valves	0.000371	0.000224	0.0000885
Connectors	0.000104	0.000104	0.0000395
OEL	0.0023	0.0000734	0.0000734
PRV	0.16	0.09792	0.09792

Emission factors obtained from Memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, Analysis of Emisson Reduction Techniques for Equipment Leaks, December 21, 2011. [EPA-HQ-OAR-2002-0037-0180]

Well Pad Model Plant 2
Subpart V

Type of Component	Number of Components	Initial Monitoring Fee or Unit Cost ($/comp)	Initial Monitoring Costs ($/yr) (Capital)	Initial LDAR Admin. Costs	Frequency of Monitoring (times/yr)	Subsequent Monitoring Fee ($/comp) or Charge (%)	Annual Monitoring Costs ($/yr)	Annual Maintenance Costs ($/yr)	Initial Leak Fraction	Initial Number of Leaks	Subsequent Leak Frequency (%)	Annual Number of Leaks	Percent Repaired OnLine	Repair Time (hours)	Labor Charge ($/hr)	Annual OnLine Leak Repair Cost ($/yr)	Percent Requiring Further Repair	Repair Time (hours)	Labor Charge ($/hr)	Annual Offline Leak Repair Cost ($/yr)	Monitoring to Verify Repair ($)	Annual Admin. Cost ($/yr)	Annual Misc. Charges ($/yr)
Valves (UU)																							
* Gas/vapor service	235	23.80	5799.69		12	1.50	4230.00		0.0118	2.77	1.18	33.28	75	0.17	66.24	132.74	25	4.00	66.24	2204.20			
Connectors																							
* Flanges - gas/vapor	863	1.10	949.30																				
Pressure Relief Devices																							
* Disks	10	122.11	1221.10		0	2.00	0.00	25.00															48.84
* Disk holders, valves,etc.	10	6374.29	63742.90			5.00		3200.00															2549.72
Open-Ended Lines	29	140.92	4086.68			5.00		203.00															163.47
Monitoring Device	1	$10,800	$10,800																				
Monitoring Device - Rent	0																						
Data Collection System	1	$14,500	$14,500																				
Sum of components:	1137																						
Annual Adminstrative and Reports	250	92.72																				$23,180	
- Assume 300 hr per fac																							
Initial Planning and Training	320	92.72		$29,670																			
- Assume 340 hr per fac																							
TOTALS			$101,100	$29,670			$4,230	$3,428								$132.74				$2,204.20		$23,180	$2,762.03

Capital Costs	$101,100	
Annualized Capital Costs	$19,428	
Annual Expenses	$35,937	
Annual Fixed Costs ($/yr)		$45,370
Annual Variable Costs ($/yr)		$9,995
Total Annual Costs ($/yr)		$55,365

Well Pad Model Plant 2
Controlled - Subpart VVa

Type of Component	Number of Components	Initial Monitoring Fee or Unit Cost ($/comp)	Initial Monitoring Costs ($/yr) (Capital)	Initial LDAR Admin. Costs	Frequency of Monitoring (times/yr)	Subsequent Monitoring Fee ($/comp) or Charge (%)	Annual Monitoring Costs ($/yr)	Annual Maintenance Costs ($/yr)	Initial Leak Fraction	Initial Number of Leaks	Subsequent Leak Frequency (%)	Annual Number of Leaks	Percent Repaired OnLine	Repair Time (hours)	Labor Charge ($/hr)	Annual OnLine Leak Repair Cost ($/yr)	Percent Requiring Further Repair	Repair Time (hours)	Labor Charge ($/hr)	Annual Offline Leak Repair Cost ($/yr)	Monitoring to Verify Repair ($)	Annual Admin. Cost ($/yr)	Annual Misc. Charges ($/yr)
Valves (UU)																							
* Gas/vapor service	235	23.80	6635.21		12	1.50	4230.00		0.0595	13.98	1.91	53.86	75	0.17	66.24	132.74	25	4.00	66.24	3567.82			
Connectors																							
* Flanges - gas/vapor	863	1.10	1556.92		0.25	2.50	539.38		0.0170	14.67	0.81	1.75	75	0.17	66.24	2.77	25	2.00	66.24	57.88			
Pressure Relief Devices																							
* Disks	10	122.11	1221.10		0	2.00	0.00	25.00															48.84
* Disk holders, valves,etc.	10	6374.29	63742.90			5.00		3200.00															2549.72
Open-Ended Lines	29	140.92	4086.68			5.00		203.00															163.47
Monitoring Device	1	$10,800	$10,800																				
Monitoring Device - Rent	0																						
Data Collection System	1	$14,500	$14,500																				
Sum of components:	1137																						
Annual Adminstrative and Reports	250	92.72																				$23,180	
- Assume 300 hr per fac																							
Initial Planning and Training	320	92.72		$29,670																			
- Assume 340 hr per fac																							
TOTALS			$102,543	$29,670			$4,769	$3,428								$135.51				$3,625.70		$23,180	$2,762.03

Capital Costs	$102,543	
Annualized Capital Costs	$19,633	
Annual Expenses	$37,901	
Annual Fixed Costs ($/yr)		$45,575
Annual Variable Costs ($/yr)		$11,959
Total Annual Costs ($/yr)		$57,534

Summary of Cost Effectiveness of the Subpart VV and Subpart VVa LDAR Programs for Gathering & Boosting

Average Model Plant Cost Effectiveness Summary for Gathering & Boosting Stations w/o Recovery Credits

Model Plant	Total Capital Investment	Annual LDAR Cost ($/yr)	Recovery Credits ($/yr)[1]	Annual LDAR Cost w/o Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions	VOC Cost Effectiveness ($/Ton)	Total HAP Emissions (Tons/yr)	Total HAP Emission Reductions	HAP Cost Effectiveness ($/Ton)
Model Plant 1													
Baseline	-----	-----		-----	179	-----	-----	49.6	-----	-----	1.87	-----	-----
V/VV	$236,278	$94,682		$94,682	109	69.3	$1,367	30.4	19.26	$4,917	1.14	0.7260	$130,416
VVa	$239,435	$99,500		$99,500	103	75.7	$1,314	28.6	21.05	$4,728	1.08	0.793	$125,403
Model Plant 2													
Baseline	-----	-----		-----	295	-----	-----	82.1	-----	-----	3.10	-----	-----
V/VV	$374,334	$135,821		$135,821	181	114.5	$1,186	50.3	31.84	$4,265	1.90	1.201	$113,133
VVa	$379,571	$143,807		$143,807	170	125.2	$1,148	47.3	34.81	$4,131	1.78	1.312	$109,568
Model Plant 3													
Baseline	-----	-----		-----	412	-----	-----	115	-----	-----	4.32	-----	-----
V/VV	$512,390	$176,960		$176,960	252	159.8	$1,107	70	44.43	$3,983	2.65	1.675	$105,642
VVa	$519,707	$188,114		$188,114	238	174.8	$1,076	66	48.58	$3,872	2.49	1.832	$102,709

[1] Annual LDAR includes no recovery credits.

Average Model Plant Cost Effectiveness Summary for Gathering & Boosting Stations w/ Recovery Credits

Model Plant	Total Capital Investment	Annual LDAR Cost ($/yr)	Recovery Credits ($/yr)[1]	Annual LDAR Cost w/ Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions	VOC Cost Effectiveness ($/Ton)	Total HAP Emissions (Tons/yr)	Total HAP Emission Reductions	HAP Cost Effectiveness ($/Ton)
Model Plant 1													
Baseline	-----	-----	-----	-----	179	-----	-----	49.6	-----	-----	1.87	-----	-----
V/VV	$236,278	$94,682	$16,058	$78,625	109	69.27	$1,135	30.4	19.26	$4,083	1.14	0.7260	$108,298
VVa	$239,435	$99,500	$17,549	$81,951	103	75.7	$1,082	28.6	21.05	$3,894	1.08	0.793	$103,285
Model Plant 2													
Baseline	-----	-----	-----	-----	295	-----	-----	82.1	-----	-----	3.10	-----	-----
V/VV	$374,334	$135,821	$26,554	$109,268	181	114.5	$954	50.3	31.84	$3,431	1.90	1.201	$91,015
VVa	$379,571	$143,807	$29,030	$114,778	170	125.2	$917	47.3	34.81	$3,297	1.78	1.312	$87,450
Model Plant 3													
Baseline	-----	-----	-----	-----	412	-----	-----	115	-----	-----	4.32	-----	-----
V/VV	$512,390	$176,960	$37,050	$139,911	252	159.8	$875	70	44.43	$3,149	2.65	1.675	$83,524
VVa	$519,707	$188,114	$40,510	$147,605	238	174.8	$845	66	48.58	$3,038	2.49	1.832	$80,591

[1] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $4/Mscf.

Gathering Station Emission Summary

Model Plant 1

	Model Plant Component Count				VOC Emissions (Tons/yr)						HAP Emissions (Tons/yr)					
Monitoring	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total VOC Emissions	Emission reduction	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total HAP Emissions	Emission reduction
Uncontrolled	547	1,723	51	29	1.960	1.730	1.133	44.805	49.628		0.074	0.065	0.043	1.689	1.871	
V	547	1,723	51	29	1.183	1.730	0.036	27.421	30.370	19.257	0.045	0.065	0.001	1.034	1.145	0.726
VV	547	1,723	51	29	1.183	1.730	0.036	27.421	30.370	19.257	0.045	0.065	0.001	1.034	1.145	0.726
VVa	547	1,723	51	29	0.467	0.657	0.036	27.421	28.582	21.046	0.018	0.025	0.001	1.034	1.078	0.793

Model Plant 2

	Model Plant Component Count				VOC Emissions (Tons/yr)						HAP Emissions (Tons/yr)					
Monitoring	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total VOC Emissions	Emission reduction	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total HAP Emissions	Emission reduction
Uncontrolled	906	2,864	83	48	3.246	2.876	1.843	74.160	82.126		0.122	0.108	0.069	2.796	3.096	
V	906	2,864	83	48	1.960	2.876	0.059	45.386	50.281	31.845	0.074	0.108	0.002	1.711	1.896	1.201
VV	906	2,864	83	48	1.960	2.876	0.059	45.386	50.281	31.845	0.074	0.108	0.002	1.711	1.896	1.201
VVa	906	2,864	83	48	0.774	1.092	0.059	45.386	47.312	34.814	0.029	0.041	0.002	1.711	1.784	1.312

Model Plant 3

	Model Plant Component Count				VOC Emissions (Tons/yr)						HAP Emissions (Tons/yr)					
Monitoring	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total VOC Emissions	Emission reduction	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total HAP Emissions	Emission reduction
Uncontrolled	1,265	4,005	115	67	4.532	4.022	2.554	103.516	114.623		0.171	0.152	0.096	3.903	4.321	
V	1,265	4,005	115	67	2.736	4.022	0.082	63.351	70.191	44.432	0.103	0.152	0.003	2.388	2.646	1.675
VV	1,265	4,005	115	67	2.736	4.022	0.082	63.351	70.191	44.432	0.103	0.152	0.003	2.388	2.646	1.675
VVa	1,265	4,005	115	67	1.081	1.528	0.082	63.351	66.042	48.582	0.041	0.058	0.003	2.388	2.490	1.832

VOC Emission Factors

	Uncontrolled (kg/hr/comp)	V _ VV (kg/hr/comp)	VVa (kg/hr/comp)
Valves	0.000371	0.000224	0.0000885
Connectors	0.000104	0.000104	0.0000395
OEL	0.0023	0.0000734	0.0000734
PRV	0.16	0.09792	0.09792

Emission factors obtained from Memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, Analysis of Emisson Reduction Techniques for Equipment Leaks, December 21, 2011. [EPA-HQ-OAR-2002-0037-0180]

Gathering & Boosting Model Plant 2
Subpart V

Type of Component	Number of Components	Initial Monitoring Fee or Unit Cost ($/comp)	Initial Monitoring Costs ($/yr) (Capital)	Initial LDAR Admin. Costs	Frequency of Monitoring (times/yr)	Subsequent Monitoring Fee ($/comp) or Charge (%)	Annual Monitoring Costs ($/yr)	Annual Maintenance Costs ($/yr)	Initial Leak Fraction	Initial Number of Leaks	Subsequent Leak Frequency (%)	Annual Number of Leaks	Percent Repaired OnLine	Repair Time (hours)	Labor Charge ($/hr)	Annual OnLine Leak Repair Cost ($/yr)	Percent Requiring Further Repair	Repair Time (hours)	Labor Charge ($/hr)	Annual Offline Leak Repair Cost ($/yr)	Monitoring to Verify Repair ($)	Annual Admin. Cost ($/yr)	Annual Misc. Charges ($/yr)
Valves (UU)																							
* Gas/vapor service	906	23.80	22359.66		12	1.50	16308.00		0.0118	10.69	1.18	128.29	75	0.17	66.24	132.74	25	4.00	66.24	8497.90			
Connectors																							
* Flanges - gas/vapor	2864	1.10	3150.40																				
Pressure Relief Devices																							
* Disks	48	122.11	5861.28		0	2.00	0.00	120.00															234.45
* Disk holders, valves,etc.	48	6374.29	305965.92			5.00		15360.00															12238.64
Open-Ended Lines	83	140.92	11696.36			5.00		581.00															467.85
Monitoring Device	1	$10,800	$10,800																				
Monitoring Device - Rent	0																						
Data Collection System	1	$14,500	$14,500																				
Sum of components:	3901																						
Annual Adminstrative and Reports	250	92.72																				$23,180	
- Assume 300 hr per fac																							
Initial Planning and Training	320	92.72		$29,670																			
- Assume 340 hr per fac																							
TOTALS			$374,334	$29,670			$16,308	$16,061								$132.74				$8,497.90		$23,180	$12,940.94

Capital Costs	$374,334	
Annualized Capital Costs	$58,701	
Annual Expenses	$77,121	
Annual Fixed Costs ($/yr)		$94,822
Annual Variable Costs ($/yr)		$41,000
Total Annual Costs ($/yr)		$135,821

Gathering & Boosting Model Plant 2
Controlled - Subpart VVa

Type of Component	Number of Components	Initial Monitoring Fee or Unit Cost ($/comp)	Initial Monitoring Costs ($/yr) (Capital)	Initial LDAR Admin. Costs	Frequency of Monitoring (times/yr)	Subsequent Monitoring Fee ($/comp) or Charge (%)	Annual Monitoring Costs ($/yr)	Annual Maintenance Costs ($/yr)	Initial Leak Fraction	Initial Number of Leaks	Subsequent Leak Frequency (%)	Annual Number of Leaks	Percent Repaired OnLine	Repair Time (hours)	Labor Charge ($/hr)	Annual OnLine Leak Repair Cost ($/yr)	Percent Requiring Further Repair	Repair Time (hours)	Labor Charge ($/hr)	Annual Offline Leak Repair Cost ($/yr)	Monitoring to Verify Repair ($)	Annual Admin. Cost ($/yr)	Annual Misc. Charges ($/yr)
Valves (UU)																							
* Gas/vapor service	906	23.80	25580.84		12	1.50	16308.00		0.0595	53.91	1.91	207.66	75	0.17	66.24	132.74	25	4.00	66.24	13755.08			
Connectors																							
* Flanges - gas/vapor	2864	1.10	5166.89		0.25	2.50	1790.00		0.0170	48.69	0.81	5.80	75	0.17	66.24	2.77	25	2.00	66.24	192.08			
Pressure Relief Devices																							
* Disks	48	122.11	5861.28		0	2.00	0.00	120.00															234.45
* Disk holders, valves,etc.	48	6374.29	305965.92			5.00		15360.00															12238.64
Open-Ended Lines	83	140.92	11696.36			5.00		581.00															467.85
Monitoring Device	1	$10,800	$10,800																				
Monitoring Device - Rent	0																						
Data Collection System	1	$14,500	$14,500																				
Sum of components:	3901																						
Annual Adminstrative and Reports	250	92.72																				$23,180	
- Assume 300 hr per fac																							
Initial Planning and Training	320	92.72		$29,670																			
- Assume 340 hr per fac																							
TOTALS			$379,571	$29,670			$18,098	$16,061								$135.51				$13,947.16		$23,180	$12,940.94

Capital Costs	$379,571	
Annualized Capital Costs	$59,445	
Annual Expenses	$84,363	
Annual Fixed Costs ($/yr)		$95,566
Annual Variable Costs ($/yr)		$48,242
Total Annual Costs ($/yr)		$143,807

Summary of the Incremental Cost Effectiveness of the Subpart VVa LDAR Programs for Processing Plants

Processing Plant Cost Effectiveness Summary

LDAR Programs

LDAR Program	Total Capital Investment	Annual LDAR Cost ($/yr)	Recovery Credits ($/yr)[1]	Annual LDAR Cost w/o Recovery Credits ($/yr)	Cost Effectiveness w/o Recovery Credits: Total CH4 Emission Reductions	CH4 Cost Effectiveness ($/Ton)	Total VOC Emission Reductions	VOC Cost Effectiveness ($/Ton)	Total HAP Emission Reductions	HAP Cost Effectiveness ($/Ton)
Subpart VVa	$8,041	$12,261		$12,261	16.4	$748	4.56	$2,691	0.172	$71,374

LDAR Program	Total Capital Investment	Annual LDAR Cost ($/yr)	Recovery Credits ($/yr)[1]	Annual LDAR Cost w/ Recovery Credits ($/yr)	Cost Effectiveness w/ Recovery Credits: Total CH4 Emission Reductions	CH4 Cost Effectiveness ($/Ton)	Total VOC Emission Reductions	VOC Cost Effectiveness ($/Ton)	Total HAP Emission Reductions	HAP Cost Effectiveness ($/Ton)
Subpart VVa	$8,041	$12,261	$3,800	$8,462	16.4	$516	4.56	$1,857	0.172	$49,256

[1] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $4/Mscf.

Natural Gas Processing Plant Emission Summary

Monitoring	Model Plant Component Count				Methane Emissions (Tons/yr)					VOC Emissions (Tons/yr)					HAP Emissions (Tons/yr)				
	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total CH4 Emissions	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total VOC Emissions	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total HAP Emissions
VV	1,392	4,392	134	29	10.8	15.9	0.3	98.6	125.7	3.01	4.41	0.095	27.42	34.9	0.114	0.166	0.004	1.03	1.32
VVa	1,392	4,392	134	29	4.3	6.0	0.3	98.6	109.3	1.19	1.68	0.095	27.42	30.4	0.045	0.063	0.004	1.03	1.15

VOC Emission Factors

	VV (kg/hr/comp)	VVa (kg/hr/comp)
Valves	0.000224	0.0000885
Connectors	0.000104	0.0000395
OEL	0.0000734	0.0000734
PRV	0.09792	0.09792

Processing Model Plant
Baseline - Subpart VV

Type of Component	Number of Components	Initial Monitoring Fee or Unit Cost ($/comp)	Initial Monitoring Costs ($/yr) (Capital)	Initial LDAR Admin. Costs	Frequency of Monitoring (times/yr)	Subsequent Monitoring Fee ($/comp) or Charge (%)	Annual Monitoring Costs ($/yr)	Annual Maintenance Costs ($/yr)	Initial Leak Fraction	Initial Number of Leaks	Subsequent Leak Frequency (%)	Annual Number of Leaks	Percent Repaired OnLine	Repair Time (hours)	Labor Charge ($/hr)	Annual OnLine Leak Repair Cost ($/yr)	Percent Requiring Further Repair	Repair Time (hours)	Labor Charge ($/hr)	Annual Offline Leak Repair Cost ($/yr)	Monitoring to Verify Repair ($)	Annual Admin. Cost ($/yr)	Annual Misc. Charges ($/yr)
Valves (UU)																							
* Gas/vapor service	1,392	23.80	34353.91		12	1.50	25056.00		0.0118	16.43	1.18	197.11	75	0.17	66.24	132.74	25	4.00	66.24	13056.38			
Connectors																							
* Flanges - gas/vapor	4392	1.10	4831.20																				
Pressure Relief Devices																							
* Disks	29	122.11	3541.19		0	2.00	0.00	72.50															141.65
* Disk holders, valves,etc.	29	6374.29	184854.41			5.00		9280.00															7394.18
Open-Ended Lines	134	140.92	18883.28			5.00		938.00															755.33
Monitoring Device	1	$10,800	$10,800																				
Monitoring Device - Rent	0																						
Data Collection System	1	$14,500	$14,500																				
Sum of components:	5947																						
Annual Adminstrative and Reports	250	92.72																				$23,180	
- Assume 300 hr per fac																							
Initial Planning and Training	320	92.72		$29,670																			
- Assume 340 hr per fac																							
TOTALS			$271,764	$29,670			$25,056	$10,291								$132.74				$13,056.38		$23,180	$8,291.16

Capital Costs	$271,764	
Annualized Capital Costs	$43,899	
Annual Expenses	$80,007	
Annual Fixed Costs ($/yr)		$75,370
Annual Variable Costs ($/yr)		$48,536
Total Annual Costs ($/yr)		$123,906

Processing Model Plant
Controlled - Subpart VVa

Type of Component	Number of Components	Initial Monitoring Fee or Unit Cost ($/comp)	Initial Monitoring Costs ($/yr) (Capital)	Initial LDAR Admin. Costs	Frequency of Monitoring (times/yr)	Subsequent Monitoring Fee ($/comp) or Charge (%)	Annual Monitoring Costs ($/yr)	Annual Maintenance Costs ($/yr)	Initial Leak Fraction	Initial Number of Leaks	Subsequent Leak Frequency (%)	Annual Number of Leaks	Percent Repaired OnLine	Repair Time (hours)	Labor Charge ($/hr)	Annual OnLine Leak Repair Cost ($/yr)	Percent Requiring Further Repair	Repair Time (hours)	Labor Charge ($/hr)	Annual Offline Leak Repair Cost ($/yr)	Monitoring to Verify Repair ($)	Annual Admin. Cost ($/yr)	Annual Misc. Charges ($/yr)
Valves (UU)																							
* Gas/vapor service	1,392	23.80	39303.02		12	1.50	25056.00		0.0595	82.82	1.91	319.05	75	0.17	66.24	132.74	25	4.00	66.24	21133.63			
Connectors																							
* Flanges - gas/vapor	4392	1.10	7923.53		0.25	2.50	2745.00		0.0170	74.66	0.81	8.89	75	0.17	66.24	2.77	25	2.00	66.24	294.56			
Pressure Relief Devices																							
* Disks	29	122.11	3541.19		0	2.00	0.00	72.50															141.65
* Disk holders, valves,etc.	29	6374.29	184854.41			5.00		9280.00															7394.18
Open-Ended Lines	134	140.92	18883.28			5.00		938.00															755.33
Monitoring Device	1	$10,800	$10,800																				
Monitoring Device - Rent	0																						
Data Collection System	1	$14,500	$14,500																				
Sum of components:	5947																						
Annual Adminstrative and Reports	250	92.72																				$23,180	
- Assume 300 hr per fac																							
Initial Planning and Training	320	92.72		$29,670																			
- Assume 340 hr per fac																							
TOTALS			$279,805	$29,670			$27,801	$10,291								$135.51				$21,428.20		$23,180	$8,291.16

Capital Costs	$279,805	
Annualized Capital Costs	$45,041	
Annual Expenses	$91,126	
Annual Fixed Costs ($/yr)		$76,512
Annual Variable Costs ($/yr)		$59,655
Total Annual Costs ($/yr)		$136,168

Summary of Cost Effectiveness of the Subpart VV and Subpart VVa LDAR Programs for Transmission and Storage

Average Model Plant Cost Effectiveness Summary for Transmission & Storage Facilities w/o Recovery Credits

Model Plant	Total Capital Investment	Annual LDAR Cost ($/yr)	Recovery Credits ($/yr)[1]	Annual LDAR Cost w/ Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions	VOC Cost Effectiveness ($/Ton)	Total HAP Emissions (Tons/yr)	Total HAP Emission Reductions	HAP Cost Effectiveness ($/Ton)
Model Plant Transmission													
Baseline	-----	-----	-----	-----	75.7	-----	-----	2.09	-----	-----	0.0622	-----	-----
V/VV	$151,669	$78,728	N/A	N/A	50.3	25.4	$3,103	1.39	0.702	$112,127	0.0413	0.0209	$3,775,122
VVa	$156,332	$85,601	N/A	N/A	21.5	54.1	$1,581	0.596	1.50	$57,144	0.0177	0.0445	$1,923,920
Model Plant Storage													
Baseline	-----	-----	-----	-----	401	-----	-----	11.1	-----	-----	0.330	-----	-----
V/VV	$571,841	$206,513	N/A	N/A	127	274	$753	3.51	7.59	$27,201	0.104	0.226	$915,799
VVa	$582,574	$222,970	N/A	N/A	62.8	338	$659	1.74	9.36	$23,819	0.0516	0.278	$801,954

[1] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $4/Mscf.

Transmission and Storage Emission Summary

Model Plant 1 - Transmission

	Model Plant Component Count				Methane Emissions (Tons/yr)					VOC Emissions (Tons/yr)						HAP Emissions (Tons/yr)					
Monitoring	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total CH4 Emissions	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total VOC Emissions	Emission reduction	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total HAP Emissions	Emission reduction
Uncontrolled	704	3,068	7	15	34.92	25.80	9.61	5.32	75.66	0.966	0.714	0.266	0.147	2.09	--	0.0287	0.0212	0.0079	0.0044	0.06	--
V	704	3,068	7	15	21.09	25.80	0.14	3.26	50.29	0.584	0.714	0.004	0.090	1.39		0.0173	0.0212	0.0001	0.0027	0.04	
VV	704	3,068	7	15	21.09	25.80	0.14	3.26	50.29	0.584	0.714	0.004	0.090	1.39	0.70	0.0173	0.0212	0.0001	0.0027	0.04	0.02
VVa	704	3,068	7	15	8.33	9.80	0.14	3.26	21.53	0.231	0.271	0.004	0.090	0.60	1.50	0.0068	0.0081	0.0001	0.0027	0.02	0.04

Model Plant 1 - Storage

	Model Plant Component Count				Methane Emissions (Tons/yr)					VOC Emissions (Tons/yr)						HAP Emissions (Tons/yr)					
Monitoring	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total CH4 Emissions	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total VOC Emissions	Emission reduction	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Total HAP Emissions	Emission reduction
Uncontrolled	1,898	5,660	367	68	94.15	47.60	235.18	24.12	401.05	2.606	1.317	6.508	0.668	11.10		0.0774	0.0391	0.1933	0.0198	0.33	
V	1,898	5,660	367	68	56.85	47.60	7.51	14.76	126.72	1.573	1.317	0.208	0.409	3.51		0.0467	0.0391	0.0062	0.0121	0.10	
VV	1,898	5,660	367	68	56.85	47.60	7.51	14.76	126.72	1.573	1.317	0.208	0.409	3.51	7.59	0.0467	0.0391	0.0062	0.0121	0.10	0.23
VVa	1,898	5,660	367	68	22.46	18.08	7.51	14.76	62.81	0.622	0.500	0.208	0.409	1.74	9.36	0.0185	0.0149	0.0062	0.0121	0.05	0.28

Methane Emission Factors - Transmission & Storage

	Uncontrolled (ton/yr/comp)	V _ VV (ton/yr/comp)	VVa (ton/yr/comp)	V _ VV	VVa
Valves	0.0496	0.0300	0.0118	39.6%	76.1%
Connectors	0.0084	0.0084	0.0032	0.0%	62.0%
OEL	0.6408	0.0205	0.0205	96.8%	96.8%
PRV	0.3547	0.2171	0.2171	38.8%	38.8%

Calculated from Table 4-17 and Table 4-24 of Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks
The emission factors for V_VV and Vva were estimated using the emission reductions that were obtained for the various components from the Uniform Standards data.
Memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, Analysis of Emisson Reduction Techniques for Equipment Leaks, December 21, 2011. [EPA-HQ-OAR-2002-0037-0180]

Weight Ratios for Estimating Emissions

	Transmission & Storage
VOC:Methane	0.027674689
HAP:Methane	0.000821985

Transmission Model Plant
Subpart V

Type of Component	Number of Components	Initial Monitoring Fee or Unit Cost ($/comp)	Initial Monitoring Costs ($/yr) (Capital)	Initial LDAR Admin. Costs	Frequency of Monitoring (times/yr)	Subsequent Monitoring Fee ($/comp) or Charge (%)	Annual Monitoring Costs ($/yr)	Annual Maintenance Costs ($/yr)	Initial Leak Fraction	Initial Number of Leaks	Subsequent Leak Frequency (%)	Annual Number of Leaks	Percent Repaired OnLine	Repair Time (hours)	Labor Charge ($/hr)	Annual OnLine Leak Repair Cost ($/yr)	Percent Requiring Further Repair	Repair Time (hours)	Labor Charge ($/hr)	Annual Offline Leak Repair Cost ($/yr)	Monitoring to Verify Repair ($)	Annual Admin. Cost ($/yr)	Annual Misc. Charges ($/yr)
Valves (UU)																							
* Gas/vapor service	704	23.80	17374.39		12	1.50	12672.00		0.0118	8.31	1.18	99.69	75	0.17	66.24	132.74	25	4.00	66.24	6603.23			
Connectors																							
* Flanges - gas/vapor	3068	1.10	3374.80																				
Pressure Relief Devices																							
* Disks	15	122.11	1831.65		0	2.00	0.00	37.50															73.27
* Disk holders, valves,etc.	15	6374.29	95614.35			5.00		4800.00															3824.57
Open-Ended Lines	58	140.92	8173.36			5.00		406.00															326.93
Monitoring Device	1	$10,800	$10,800																				
Monitoring Device - Rent	0																						
Data Collection System	1	$14,500	$14,500																				
Sum of components:	3845																						
Annual Adminstrative and Reports	250	92.72																				$23,180	
- Assume 300 hr per fac																							
Initial Planning and Training	320	92.72		$29,670																			
- Assume 340 hr per fac																							
TOTALS			$151,669	$29,670			$12,672	$5,244								$132.74				$6,603.23		$23,180	$4,224.77
Capital Costs	$151,669																						
Annualized Capital Costs	$26,671																						
Annual Expenses	$52,056																						
Annual Fixed Costs ($/yr)		$54,076																					
Annual Variable Costs ($/yr)		$24,651																					
Total Annual Costs ($/yr)		$78,728																					

Transmission Model Plant
Controlled - Subpart VVa

Type of Component	Number of Components	Initial Monitoring Fee or Unit Cost ($/comp)	Initial Monitoring Costs ($/yr) (Capital)	Initial LDAR Admin. Costs	Frequency of Monitoring (times/yr)	Subsequent Monitoring Fee ($/comp) or Charge (%)	Annual Monitoring Costs ($/yr)	Annual Maintenance Costs ($/yr)	Initial Leak Fraction	Initial Number of Leaks	Subsequent Leak Frequency (%)	Annual Number of Leaks	Percent Repaired OnLine	Repair Time (hours)	Labor Charge ($/hr)	Annual OnLine Leak Repair Cost ($/yr)	Percent Requiring Further Repair	Repair Time (hours)	Labor Charge ($/hr)	Annual Offline Leak Repair Cost ($/yr)	Monitoring to Verify Repair ($)	Annual Admin. Cost ($/yr)	Annual Misc. Charges ($/yr)
Valves (UU)																							
* Gas/vapor service	704	23.80	19877.39		12	1.50	12672.00		0.0595	41.89	1.91	161.36	75	0.17	66.24	132.74	25	4.00	66.24	10688.27			
Connectors																							
* Flanges - gas/vapor	3068	1.10	5534.92		0.25	2.50	1917.50		0.0170	52.16	0.81	6.21	75	0.17	66.24	2.77	25	2.00	66.24	205.76			
Pressure Relief Devices																							
* Disks	15	122.11	1831.65		0	2.00	0.00	37.50															73.27
* Disk holders, valves,etc.	15	6374.29	95614.35			5.00		4800.00															3824.57
Open-Ended Lines	58	140.92	8173.36			5.00		406.00															326.93
Monitoring Device	1	$10,800	$10,800																				
Monitoring Device - Rent	0																						
Data Collection System	1	$14,500	$14,500																				
Sum of components:	3845																						
Annual Adminstrative and Reports	250	92.72																				$23,180	
- Assume 300 hr per fac																							
Initial Planning and Training	320	92.72		$29,670																			
- Assume 340 hr per fac																							
TOTALS			$156,332	$29,670			$14,590	$5,244								$135.51				$10,894.04		$23,180	$4,224.77
Capital Costs	$156,332																						
Annualized Capital Costs	$27,334																						
Annual Expenses	$58,267																						
Annual Fixed Costs ($/yr)		$54,738																					
Annual Variable Costs ($/yr)		$30,863																					
Total Annual Costs ($/yr)		$85,601																					

Storage Model Plant
Subpart V

Type of Component	Number of Components	Initial Monitoring Fee or Unit Cost ($/comp)	Initial Monitoring Costs ($/yr) (Capital)	Initial LDAR Admin. Costs	Frequency of Monitoring (times/yr)	Subsequent Monitoring Fee ($/comp) or Charge (%)	Annual Monitoring Costs ($/yr)	Annual Maintenance Costs ($/yr)	Initial Leak Fraction	Initial Number of Leaks	Subsequent Leak Frequency (%)	Annual Number of Leaks	Percent Repaired OnLine	Repair Time (hours)	Labor Charge ($/hr)	Annual OnLine Leak Repair Cost ($/yr)	Percent Requiring Further Repair	Repair Time (hours)	Labor Charge ($/hr)	Annual Offline Leak Repair Cost ($/yr)	Monitoring to Verify Repair ($)	Annual Admin. Cost ($/yr)	Annual Misc. Charges ($/yr)
Valves (UU)																							
* Gas/vapor service	1,898	23.80	46841.75		12	1.50	34164.00		0.0118	22.40	1.18	268.76	75	0.17	66.24	132.74	25	4.00	66.24	17802.45			
Connectors																							
* Flanges - gas/vapor	5660	1.10	6226.00																				
Pressure Relief Devices																							
* Disks	68	122.11	8303.48		0	2.00	0.00	170.00															332.14
* Disk holders, valves,etc.	68	6374.29	433451.72			5.00		21760.00															17338.07
Open-Ended Lines	367	140.92	51717.64			5.00		2569.00															2068.71
Monitoring Device	1	$10,800	$10,800																				
Monitoring Device - Rent	0																						
Data Collection System	1	$14,500	$14,500																				
Sum of components:	7993																						
Annual Adminstrative and Reports	250	92.72																				$23,180	
- Assume 300 hr per fac																							
Initial Planning and Training	320	92.72		$29,670																			
- Assume 340 hr per fac																							
TOTALS			$571,841	$29,670			$34,164	$24,499								$132.74				$17,802.45		$23,180	$19,738.91
Capital Costs	$571,841																						
Annualized Capital Costs	$86,996																						
Annual Expenses	$119,517																						
Annual Fixed Costs ($/yr)		$129,915																					
Annual Variable Costs ($/yr)		$76,598																					
Total Annual Costs ($/yr)		$206,513																					

Storage Model Plant
Controlled - Subpart VVa

Type of Component	Number of Components	Initial Monitoring Fee or Unit Cost ($/comp)	Initial Monitoring Costs ($/yr) (Capital)	Initial LDAR Admin. Costs	Frequency of Monitoring (times/yr)	Subsequent Monitoring Fee ($/comp) or Charge (%)	Annual Monitoring Costs ($/yr)	Annual Maintenance Costs ($/yr)	Initial Leak Fraction	Initial Number of Leaks	Subsequent Leak Frequency (%)	Annual Number of Leaks	Percent Repaired OnLine	Repair Time (hours)	Labor Charge ($/hr)	Annual OnLine Leak Repair Cost ($/yr)	Percent Requiring Further Repair	Repair Time (hours)	Labor Charge ($/hr)	Annual Offline Leak Repair Cost ($/yr)	Monitoring to Verify Repair ($)	Annual Admin. Cost ($/yr)	Annual Misc. Charges ($/yr)
Valves (UU)																							
* Gas/vapor service	1,898	23.80	53589.89		12	1.50	34164.00		0.0595	112.93	1.91	435.02	75	0.17	66.24	132.74	25	4.00	66.24	28815.83			
Connectors																							
* Flanges - gas/vapor	5660	1.10	10211.10		0.25	2.50	3537.50		0.0170	96.22	0.81	11.46	75	0.17	66.24	2.77	25	2.00	66.24	379.60			
Pressure Relief Devices																							
* Disks	68	122.11	8303.48		0	2.00	0.00	170.00															332.14
* Disk holders, valves,etc.	68	6374.29	433451.72			5.00		21760.00															17338.07
Open-Ended Lines	367	140.92	51717.64			5.00		2569.00															2068.71
Monitoring Device	1	$10,800	$10,800																				
Monitoring Device - Rent	0																						
Data Collection System	1	$14,500	$14,500																				
Sum of components:	7993																						
Annual Adminstrative and Reports	250	92.72																				$23,180	
- Assume 300 hr per fac																							
Initial Planning and Training	320	92.72		$29,670																			
- Assume 340 hr per fac																							
TOTALS			$582,574	$29,670			$37,702	$24,499								$135.51				$29,195.44		$23,180	$19,738.91
Capital Costs	$582,574																						
Annualized Capital Costs	$88,520																						
Annual Expenses	$134,450																						
Annual Fixed Costs ($/yr)		$131,439																					
Annual Variable Costs ($/yr)		$91,531																					
Total Annual Costs ($/yr)		$222,970																					

United States Environmental Protection Agency

Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

Background Technical Support Document for Proposed Standards

EPA-453/R-11-002
July 2011

Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution.

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U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
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FOREWORD

This background technical support document (TSD) provides information relevant to the proposal of New Source Performance Standards (NSPS) for limiting VOC emissions from the Oil and Natural Gas Sector. The proposed standards were developed according to section 111(b)(1)(B) under the Clean Air Act, which requires EPA to review and revise, is appropriate, NSPS standards. The NSPS review allows EPA to identify processes in the oil and natural sector that are not regulated under the existing NSPS but may be appropriate to regulate under NSPS based on new information. This would include processes that emit the current regulated pollutants, VOC and SO_2, as well as any additional pollutants that are identified. This document is the result of that review process. Chapter 1 provides introduction on NSPS regulatory authority. Chapter 2 presents an overview of the oil and natural gas sector. Chapter 3 discusses the entire NSPS review process undertaken for this review. Finally, Chapters 4-8 provide information on previously unregulated emissions sources. Each chapter describes the emission source, the estimated emissions (on average) from these sources, potential control options identified to reduce these emissions and the cost of each control option identified. In addition, secondary impacts are estimated and the rationale for the proposed NSPS for each emission source is provided.

TABLE OF CONTENTS

APPENDIX A

1.0 NEW SOURCE PERFORMANCE STANDARD BACKGROUND

Standards of performance for new stationary sources are established under section 111 of the Clean Air Act (42 U.S.C. 7411), as amended in 1977. Section 111 directs the Administrator to establish standards of performance for any category of new stationary sources of air pollution which "…causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare." This technical support document (TSD) supports the proposed standards, which would control volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from the oil and natural gas sector.

1.1 Statutory Authority

Section 111 of the Clean Air Act (CAA) requires the Environmental Protection Agency Administrator to list categories of stationary sources, if such sources cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for such source categories. A performance standard reflects the degree of emission limitation achievable through the application of the "best system of emission reduction" (BSER) which the EPA determines has been adequately demonstrated. The EPA may consider certain costs and nonair quality health and environmental impact and energy requirements when establishing performance standards. Whereas CAA section 112 standards are issued for existing and new stationary sources, standards of performance are issued for new and modified stationary sources. These standards are referred to as new source performance standards (NSPS). The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to "at least every 8 years review and, if appropriate, revise" performance standards unless the "Administrator determines that such review is not appropriate in light of readily available information on the efficacy" of the standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to "reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.” This level of control is referred to as the best system of emission reduction (BSER). In determining BSER, a technology review is conducted that identifies what emission reduction systems exist and how much the identified systems reduce air pollution in practice. For each control system identified, the costs and secondary air benefits (or disbenefits) resulting from energy requirements and non-air quality impacts such as solid waste generation are also evaluated. This analysis determines BSER. The resultant standard is usually a numerical emissions limit, expressed as a performance level (i.e., a rate-based standard or percent control), that reflects the BSER. Although such standards are based on the BSER, the EPA may not prescribe a particular technology that must be used to comply with a performance standard, except in instances where the Administrator determines it is not feasible to prescribe or enforce a standard of performance. Typically, sources remain free to elect whatever control measures that they choose to meet the emission limits. Upon promulgation, a NSPS becomes a national standard to which all new, modified or reconstructed sources must comply.

1.2 History of Oil and Natural Gas Source Category

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). On June 24, 1985 (50 FR 26122), the EPA promulgated a NSPS for the source category that addressed volatile organic compound (VOC) emissions from leaking components at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for the source category that regulates sulfur dioxide (SO_2) emissions from natural gas processing plants (40 CFR part 60, subpart LLL). Other than natural gas processing plants, EPA has not previously set NSPS for a variety of oil and natural gas operations. These NSPS are relatively narrow in scope as they address emissions only at natural gas processing plants. Specifically, subpart KKK addresses VOC emissions from leaking equipment at onshore natural gas processing plants, and subpart LLL addresses SO_2 emissions from natural gas processing plants.

1.3 NSPS Review Process Overview

CAA section 111(b)(1)(B) requires EPA to review and revise, if appropriate, NSPS standards. First, the existing NSPS were evaluated to determine whether it reflects BSER for the emission affected sources. This review was conducted by examining control technologies currently in use and assessing whether these technologies represent advances in emission reduction techniques compared to the technologies upon which the existing NSPS are based. For each new control technology identified, the potential emission reductions, costs, secondary air benefits (or disbenefits) resulting from energy requirements and non-air quality impacts such as solid waste generation are evaluated. The second step is evaluating whether there are additional pollutants emitted by facilities in the oil and natural gas sector that contribute significantly to air pollution and may reasonably be anticipated to endanger public health or welfare. The final review step is to identify additional processes in the oil and natural gas sector that are not covered under the existing NSPS but may be appropriate to develop NSPS based on new information. This would include processes that emit the current regulated pollutants, VOC and SO_2, as well as any additional pollutants that are identified. The entire review process is described in Chapter 3.

2.0 OIL AND NATURAL GAS SECTOR OVERVIEW

The oil and natural gas sector includes operations involved in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas. Specifically for oil, the sector includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the sector includes all operations from the well to the customer. The oil and natural gas operations can generally be separated into four segments: (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and (4) natural gas distribution. Each of these segments is briefly discussed below.

Oil and natural gas production includes both onshore and offshore operations. Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation or treating of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head and "Christmas tree" piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices and dehydrators. Production operations also include well drilling, completion and recompletion processes; which includes all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the "pads" where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production sector also includes the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas and other materials and wastes from the wells to the refineries or natural gas processing plants. None of the operations upstream of the natural gas processing plant (i.e. from the well to the natural gas processing plant) are covered by the existing NSPS. Offshore oil and natural gas production occurs on platform structures that house equipment to extract oil and gas from the ocean or lake floor and that process and/or transfer the oil and gas to storage, transport vessels or onshore. Offshore production can also include secondary platform structures connected to the platform structure, storage tanks associated with the platform structure and floating production and offloading equipment.

There are three basic types of wells: Oil wells, gas wells and associated gas wells. Oil wells can have "associated" natural gas that is separated and processed or the crude oil can be the only product processed. Once the crude oil is separated from the water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar or pipeline. The oil refinery sector is considered separately from the oil and natural gas sector. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

Natural gas is primarily made up of methane. However, whether natural gas is associated gas from oil wells or non-associated gas from gas or condensate wells, it commonly exists in mixtures with other hydrocarbons. These hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produced "pipeline quality" dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover natural gas liquids or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of natural gas liquids, sulfur and CO_2 removal, fractionation of natural gas liquid and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility. Natural gas processing plants are the only operations covered by the existing NSPS.

The pipeline quality natural gas leaves the processing segment and enters the transmission segment. Pipelines in the natural gas transmission segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission segment includes underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration and flow measurement.

The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines to business and household customers. The delivery point where the natural gas leaves the transmission segment and enters the distribution segment is often called the “citygate.” Typically, utilities take ownership of the gas at the citygate. Natural gas distribution systems consist of thousands of miles of piping, including mains and service pipelines to the customers. Distribution systems sometimes have compressor stations, although they are considerably smaller than transmission compressor stations. Distribution systems include metering stations, which allow distribution companies to monitor the natural gas in the system. Essentially, these metering stations measure the flow of gas and allow distribution companies to track natural gas as it flows through the system.

Emissions can occur from a variety of processes and points throughout the oil and natural gas sector. Primarily, these emissions are organic compounds such as methane, ethane, VOC and organic hazardous air pollutants (HAP). The most common organic HAP are n-hexane and BTEX compounds (benzene, toluene, ethylbenzene and xylenes). Hydrogen sulfide and SO_2 are emitted from production and processing operations that handle and treat sour gas[i]

In addition, there are significant emissions associated with the reciprocating internal combustion engines and combustion turbines that power compressors throughout the oil and natural gas sector. However, emissions from internal combustion engines and combustion turbines are covered by regulations specific to engines and turbines and, thus, are not addressed in this action.

[i] Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO_2

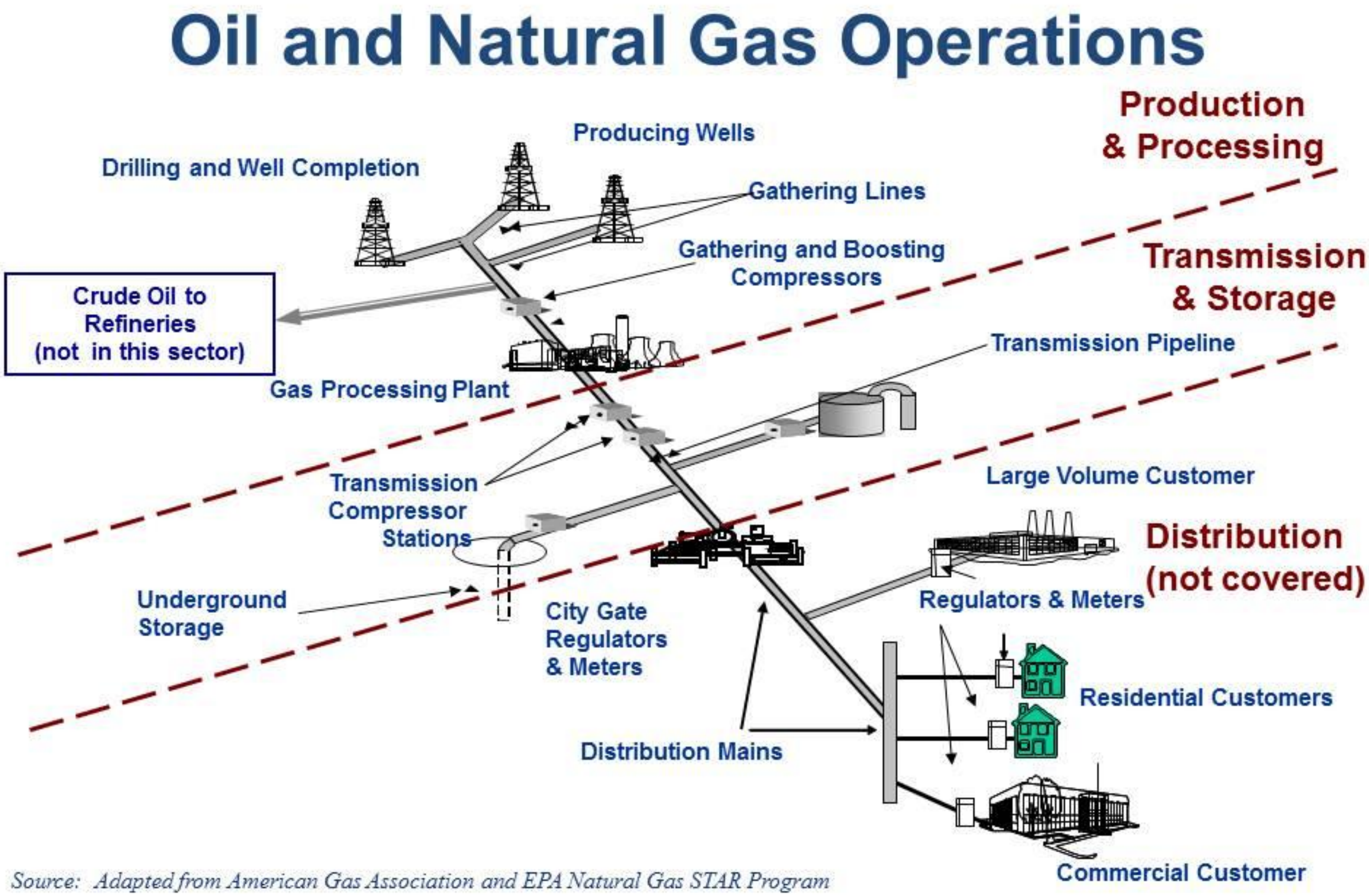

Figure 2-1. Oil and Natural Gas Operations

3.0 NEW SOURCE PERFORMANCE STANDARD REVIEW

As discussed in section 1.2, there are two NSPS that impact the oil and natural gas sector: (1) the NSPS for equipment leaks of VOC at natural gas processing plants (subpart KKK) and (2) the NSPS for SO_2 emissions from sweetening units located at natural gas processing plants (subpart LLL). Because they only address emissions from natural gas processing plants, these NSPS are relatively narrow in scope.

Section 111(b)(1) of the CAA requires the EPA to review and revise, if appropriate, NSPS standards. This review process consisted of the following steps:

1. Evaluation of the existing NSPS to determine whether they continue to reflect the BSER for the emission sources that they address;
2. Evaluation of whether there were additional pollutants emitted by facilities in the oil and natural gas sector that warrant regulation and for which there is adequate information to promulgate standards of performance; and
3. Identification of additional processes in the oil and natural gas sector for which it would be appropriate to develop performance standards, including processes that emit the currently regulated pollutants as well as any additional pollutants identified in step two.

The following sections detail each of these steps.

3.1 Evaluation of BSER for Existing NSPS

Consistent with the obligations under CAA section 111(b), control options reflected in the current NSPS for the Oil and Natural Gas source category were evaluated in order to distinguish if these options still represent BSER. To evaluate the BSER options for equipment leaks the following was reviewed: EPA's current leak detection and repair (LDAR) programs, the Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database, and emerging technologies that have been identified by partners in the Natural Gas STAR program.[1]

3.1.1 BSER for VOC Emissions from Equipment Leaks at Natural Gas Processing Plants

The current NSPS for equipment leaks of VOC at natural gas processing plants (40 CFR part 60, subpart KKK) requires compliance with specific provisions of 40 CFR part 60, subpart VV, which is a LDAR program, based on the use of EPA Method 21 to identify equipment leaks. In addition to the subpart VV requirements, the LDAR requirements in 40 CFR part 60, subpart VVa were also reviewed. This LDAR program is considered to be more stringent than the subpart VV requirements, because it has lower component leak threshold definitions and more frequent monitoring, in comparison to the subpart VV program. Furthermore, subpart VVa requires monitoring of connectors, while subpart VV does not. Options based on optical gas imaging were also reviewed.

The currently required LDAR program for natural gas processing plants (40 CFR part 60, subpart KKK) is based on EPA Method 21, which requires the use of an organic vapor analyzer to monitor components and to measure the concentration of the emissions in identifying leaks. Although there have been advancements in the use of optical gas imaging to detect leaks from these same types of components, these instruments do not yet provide a direct measure of leak concentrations. The instruments instead provide a measure of a leak relative to an instrument specific calibration point. Since the promulgation of 40 CFR part 60, subpart KKK (which requires Method 21 leak measurement monthly), the EPA has updated the 40 CFR part 60 General Provisions to allow the use of advanced leak detection tools, such as optical gas imaging and ultrasound equipment as an alternative to the LDAR protocol based on Method 21 leak measurements (see 40 CFR 60.18(g)). The alternative work practice allowing use of these advanced technologies includes a provision for conducting a Method 21-based LDAR check of the regulated equipment annually to verify good performance.

In considering BSER for VOC equipment leaks at natural gas processing plants, four options were evaluated. One option evaluated consists of changing from a 40 CFR part 60, subpart VV-level program, which is what 40 CFR part 60, subpart KKK currently requires, to a 40 CFR part 60, subpart VVa program, which applies to new synthetic organic chemical plants after 2006. Subpart VVa lowers the leak definition for valves from 10,000 parts per million (ppm) to 500 ppm, and requires the monitoring of connectors. In our analysis of these impacts, it was estimated that, for a typical natural gas processing plant, the incremental cost effectiveness of changing from the current subpart VV-level program to a subpart VVa-level program using Method 21 is $3,352 per ton of VOC reduction.

In evaluating 40 CFR part 60, subpart VVa-level LDAR at processing plants, the individual types of components (valves, connectors, pressure relief devices and open-ended lines) were also analyzed separately to determine cost effectiveness for individual components. Detailed discussions of these component-by-component analyses are provided in Chapter 8. Cost effectiveness ranged from $144 per ton of VOC (for valves) to $4,360 per ton of VOC (for connectors), with no change in requirements for pressure relief devices and open-ended lines.

Another option evaluated for gas processing plants was the use of optical gas imaging combined with an annual EPA Method 21 check (i.e., the alternative work practice for monitoring equipment for leaks at 40 CFR 60.18(g)). It was previously determined that the VOC reduction achieved by this combination of optical gas imaging and Method 21 would be equivalent to reductions achieved by the 40 CFR part 60, subpart VVa-level program. Based on the emission reduction level, the cost effectiveness of this option was estimated to be $6,462 per ton of VOC reduction. This analysis was based on the facility purchasing an optical gas imaging system costing $85,000. However, at least one manufacturer was identified that rents the optical gas imaging systems. That manufacturer rents the optical gas imaging system for $3,950 per week. Using this rental cost in place of the purchase cost, the VOC cost effectiveness of the monthly optical gas imaging combined with annual Method 21 inspection visits is $4,638 per ton of VOC reduction.[i]

A third option evaluated consisted of monthly optical gas imaging without an annual Method 21 check. The annual cost of the monthly optical gas imaging LDAR program was estimated to be $76,581 based on camera purchase, or $51,999 based on camera rental. However, it is not possible to quantify the VOC emission reductions achieved by an optical imaging program alone, therefore the cost effectiveness of this option could not be determined. Finally, a fourth option was evaluated that was similar to the third option, except that the optical gas imaging would be performed annually rather than monthly. For this option, the annual cost was estimated to be $43,851, based on camera purchase, or $18,479, based on camera rental.

Because the cost effectiveness of options 3 and 4 could not be estimated, these options could not be identified as BSER for reducing VOC leaks at gas processing plants. Because options 1 and 2 achieve equivalent VOC reduction and are both cost effective, both options 1 and 2 reflect BSER for LDAR for natural gas processing plants. As mentioned above, option 1 is the LDAR in 40 CFR part 60, subpart VVa and option 2 is the alternative work practice at 40 CFR 60.18(g) and is already available to use as an alternative to subpart VVa LDAR.

3.1.2 BSER for SO_2 Emissions from Sweetening Units at Natural Gas Processing Plants

For 40 CFR part 60, subpart LLL, control systems for SO_2 emissions from sweetening units located at natural gas processing plants were evaluated, including those followed by a sulfur recovery unit. Subpart

[i] Because optical gas imaging is used to view multiple pieces of equipment at a facility during one leak survey, options involving imaging are not amenable to a component by component analysis.

LLL provides specific standards for SO_2 emission reduction efficiency, on the basis of sulfur feed rate and the sulfur content of the natural gas.

According to available literature, the most widely used process for converting H_2S in acid gases (i.e., H_2S and CO_2) separated from natural gas by a sweetening process (such as amine treating) into elemental sulfur is the Claus process. Sulfur recovery efficiencies are higher with higher concentrations of H_2S in the feed stream due to the thermodynamic equilibrium limitation of the Claus process. The Claus sulfur recovery unit produces elemental sulfur from H_2S in a series of catalytic stages, recovering up to 97-percent recovery of the sulfur from the acid gas from the sweetening process. Further, sulfur recovery is accomplished by making process modifications or by employing a tail gas treatment process to convert the unconverted sulfur compounds from the Claus unit.

In addition, process modifications and tail gas treatment options were also evaluated at the time 40 CFR part 60, subpart LLL was proposed.[ii] As explained in the preamble to the proposed subpart LLL, control through sulfur recovery with tail gas treatment may not always be cost effective, depending on sulfur feed rate and inlet H_2S concentrations. Therefore, other methods of increasing sulfur recovery via process modifications were evaluated.

As shown in the original evaluation for the proposed subpart LLL, the performance capabilities and costs of each of these technologies are highly dependent on the ratio of H_2S and CO_2 in the gas stream and the total quantity of sulfur in the gas stream being treated. The most effective means of control was selected as BSER for the different stream characteristics. As a result, separate emissions limitations were developed in the form of equations that calculate the required initial and continuous emission reduction efficiency for each plant. The equations were based on the design performance capabilities of the technologies selected as BSER relative to the gas stream characteristics.[iii] The emission limit for sulfur feed rates at or below 5 long tons per day, regardless of H_2S content, was 79 percent. For facilities with sulfur feed rates above 5 long tons per day, the emission limits ranged from 79 percent at an H_2S content below 10 percent to 99.8 percent for H_2S contents at or above 50 percent.

To review these emission limitations, a search was performed of the RBLC database[1] and state regulations. No State regulations were identified that included emission limitations more stringent than 40 CFR part 60, subpart LLL. However, two entries in the RBLC database were identified having SO_2

[ii] 49 FR 2656, 2659-2660 (1984).
[iii] 49 FR 2656, 2663-2664 (1984).

emission reductions of 99.9 percent. One entry is for a facility in Bakersfield, California, with a 90 long ton per day sulfur recovery unit followed by an amine-based tailgas treating unit. The second entry is for a facility in Coden, Alabama, with a sulfur recovery unit with a feed rate of 280 long tons of sulfur per day, followed by selective catalytic reduction and a tail gas incinerator. However, neither of these entries contained information regarding the H_2S contents of the feed stream. Because the sulfur recovery efficiency of these large sized plants was greater than 99.8 percent, the original data was reevaluated. Based on the available cost information, a 99.9 percent efficiency is cost effective for facilities with a sulfur feed rate greater than 5 long tons per day and H_2S content equal to or greater than 50 percent. Based on this review, the maximum initial and continuous efficiency for facilities with a sulfur feed rate greater than 5 long tons per day and a H_2S content equal to or greater than 50 percent is raised to 99.9 percent.

The search of the RBLC database did not uncover information regarding costs and achievable emission reductions to suggest that the emission limitations for facilities with a sulfur feed rate less than 5 long tons per day or H_2S content less than 50 percent should be modified. Therefore, there were not any identifiable changes to the emissions limitations for facilities with sulfur feed rate and H_2S content less than 5 long tons per day and 50 percent, respectively.[1]

3.2 Additional Pollutants

The two current NSPS for the Oil and Natural Gas source category address emissions of VOC and SO_2. In addition to these pollutants, sources in this source category also emit a variety of other pollutants, most notably, air toxics. However, there are NESHAP that address air toxics from the oil and natural gas sector, specifically 40 CFR subpart HH and 40 CFR subpart HHH.

In addition, processes in the Oil and Natural Gas source category emit significant amounts of methane. The 1990 - 2009 U.S. GHG Inventory estimates 2009 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries) to be 251.55 MMtCO2e (million metric tons of CO2-equivalents (CO2e)).[iv] The emissions estimated from well completions and recompletions exclude a significant number of wells completed in tight sand plays, such as the Marcellus, due to availability of data when the 2009 Inventory was developed. The estimate in this proposal includes an adjustment for tight sand plays (being considered as a planned improvement in development of the 2010 Inventory).

[iv] U.S. EPA. Inventory of U.S. Greenhouse Gas Inventory and Sinks. 1990 - 2009.
http://www.epa.gov/climatechange/emissions/downloads10/US-GHGInventory2010_ExecutiveSummary.pdf

This adjustment would increase the 2009 Inventory estimate by 76.74 MMtCO2e. The total methane emissions from Petroleum and Natural Gas Systems, based on the 2009 Inventory, adjusted for tight sand plays and the Marcellus, is 328.29 MMtCO2e.

Although this proposed rule does not include standards for regulating the GHG emissions discussed above, EPA continues to assess these significant emissions and evaluate appropriate actions for addressing these concerns. Because many of the proposed requirements for control of VOC emissions also control methane emissions as a co-benefit, the proposed VOC standards would also achieve significant reduction of methane emissions.

Significant emissions of oxides of nitrogen (NO_x) also occur at oil and natural gas sites due to the combustion of natural gas in reciprocating engines and combustion turbines used to drive the compressors that move natural gas through the system, and from combustion of natural gas in heaters and boilers. While these engines, turbines, heaters and boilers are co-located with processes in the oil and natural gas sector, they are not in the Oil and Natural Gas source category and are not being addressed in this action. The NO_x emissions from engines and turbines are covered by the Standards of Performance for Stationary Spark Internal Combustion Engines (40 CFR part 60, subpart JJJJ) and Standards of Performance for Stationary Combustion Turbines (40 CFR part 60, subpart KKKK), respectively.

An additional source of NO_x emissions would be pit flaring of VOC emissions from well completions. As discussed in Chapter 4 Well completions, pit flaring is one option identified for controlling VOC emissions. Because there is no way of directly measuring the NO_x produced, nor is there any way of applying controls other than minimizing flaring, flaring would only be required for limited conditions.

3.3 Additional Processes

The current NSPS only cover emissions of VOC and SO_2 from one type of facility in the oil and natural gas sector, which is the natural gas processing plant. This is the only type of facility in the Oil and Natural Gas source category where SO_2 is expected to be emitted directly; although H_2S contained in sour gas[v] forms SO_2 as a product of oxidation when oxidized in the atmosphere or combusted in boilers and heaters in the field. These field boilers and heaters are not part of the Oil and Natural Gas source category and are generally too small to be regulated by the NSPS covering boilers (i.e., they have a heat

[v] Sour gas is defined as natural gas with a maximum H_2S content of 0.25 gr/100 scf (4ppmv) along with the presence of CO_2.

input of less than 10 million British Thermal Units per hour). They may, however, be included in future rulemakings.

In addition to VOC emissions from gas processing plants, there are numerous sources of VOC throughout the oil and natural gas sector that are not addressed by the current NSPS. Pursuant to CAA section 111(b), a modification of the listed category will now include all segments of the oil and natural gas industry for regulation. In addition, VOC standards will now cover additional processes at oil and natural gas operations. These include NSPS for VOC from gas well completions and recompletions, pneumatic controllers, compressors and storage vessels. In addition, produced water ponds may also be a potentially significant source of emissions, but there is very limited information available regarding these emissions. Therefore, no options could be evaluated at this time. The remainder of this document presents the evaluation for each of the new processes to be included in the NSPS.

3.4 References

1 Memorandum to Bruce Moore from Brad Nelson and Phil Norwood. Crude Oil and Natural Gas Production NSPS Technology Reviews. EC/R Incorporated. July 28, 2011.

4.0 WELL COMPLETIONS AND RECOMPLETIONS

In the oil and natural gas sector, well completions and recompletions contain multi-phase processes with various sources of emissions. One specific emission source during completion and recompletion 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 recompletion activities that involve re-drilling or re-fracturing an existing well. This chapter describes completions and recompletions, and provides estimates for representative wells in addition to nationwide emissions. Control techniques employed to reduce emissions from flowback gas venting during completions and recompletions are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for reducing flowback emissions during completions and recompletions.

4.1 Process Description

4.1.1 Oil and Gas Well Completions

All oil and natural gas wells must be "completed" after initial drilling in preparation for production. Oil and natural gas completion activities not only will vary across formations, but can vary between wells in the same formation. Over time, completion and recompletion activities may change due to the evolution of well characteristics and technology advancement. Conventional gas reservoirs have well defined formations with high resource allocation in permeable and porous formations, and wells in conventional gas reservoirs have generally not required stimulation during production. Unconventional gas reservoirs are more dispersed and found in lower concentrations and may require stimulation (such as hydraulic fracturing) to extract gas.[1]

Well completion activities 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. Surface components, including wellheads, pumps, dehydrators, separators, tanks, and gathering lines are installed as necessary for production to begin. The flowback stage of a well completion is highly variable but typically lasts between 3 and 10 days for the average well.[2]

Developmental wells are drilled within known boundaries of a proven oil or gas field, and are located near existing well sites where well parameters are already recorded and necessary surface equipment is in place. When drilling occurs in areas of new or unknown potential, well parameters such as gas composition, flow rate, and temperature from the formation need to be ascertained before surface facilities required for production can be adequately sized and brought on site. In this instance, exploratory (also referred to as "wildcat") wells and field boundary delineation wells typically either vent or combust the flowback gas.

One completion step for improving gas production is to fracture the reservoir rock with very high pressure fluid, typically a water emulsion with a proppant (generally sand) that "props open" the fractures after fluid pressure is reduced. Natural gas emissions are a result of the backflow of the fracture fluids and reservoir gas at high pressure and velocity necessary to clean and lift excess proppant to the surface. Natural gas from the completion backflow escapes to the atmosphere during the reclamation of water, sand, and hydrocarbon liquids during the collection of the multi-phase mixture directed to a surface impoundment. As the fracture fluids are depleted, the backflow eventually contains a higher volume of natural gas from the formation. Due to the additional equipment and resources involved and the nature of the backflow of the fracture fluids, completions involving hydraulic fracturing have higher costs and vent substantially more natural gas than completions not involving hydraulic fracturing.

Hydraulic fracturing can and does occur in some conventional reservoirs, but it is much more common in "tight" formations. Therefore, this analysis assumes hydraulic fracturing is performed in tight sand, shale, and coalbed methane formations. This analysis defines tight sand as sandstones or carbonates with an in situ permeability (flow rate capability) to gas of less than 0.1 millidarcy.[i]

"Energized fractures" are a relatively new type of completion method that injects an inert gas, such as carbon dioxide or nitrogen, before the fracture fluid and proppant. Thus, during initial flowback, the gas stream will first contain a high proportion of the injected gas, which will gradually decrease overtime.

4.1.2 Oil and Gas Well Recompletions

Many times wells will need supplementary maintenance, referred to as recompletions (these are also referred to as workovers). Recompletions are remedial operations required to maintain production or minimize the decline in production. Examples of the variety of recompletion activities include

[i] A darcy (or darcy unit) and millidarcies (mD) are units of permeability Converted to SI units, 1 darcy is equivalent to 9.869233×10^{-13} m² or 0.9869233 (µm)². This conversion is usually approximated as 1 (µm)².

completion of a new producing zone, re-fracture of a previously fractured zone, removal of paraffin buildup, replacing rod breaks or tubing tears in the wellbore, and addressing a malfunctioning downhole pump. During a recompletion, portable equipment is conveyed back to the well site temporarily and some recompletions require the use of a service rig. As with well completions, recompletions are highly specialized activities, requiring special equipment, and are usually performed by well service contractors specializing in well maintenance. Any flowback event during a recompletion, such as after a hydraulic fracture, will result in emissions to the atmosphere unless the flowback gas is captured.

When hydraulic re-fracturing is performed, the emissions are essentially the same as new well completions involving hydraulic fracture, except that surface gas collection equipment will already be present at the wellhead after the initial fracture. The backflow velocity during re-fracturing will typically be too high for the normal wellhead equipment (separator, dehydrator, lease meter), while the production separator is not typically designed for separating sand.

Backflow emissions are not a direct result of produced water. Backflow emissions are a result of free gas being produced by the well during well cleanup event, when the well also happens to be producing liquids (mostly water) and sand. The high rate backflow, with intermittent slugs of water and sand along with free gas, is typically directed to an impoundment or vessels until the well is fully cleaned up, where the free gas vents to the atmosphere while the water and sand remain in the impoundment or vessels. Therefore, nearly all of the backflow emissions originate from the recompletion process but are vented as the backflow enters the impoundment or vessels. Minimal amounts of emissions are caused by the fluid (mostly water) held in the impoundment or vessels since very little gas is dissolved in the fluid when it enters the impoundment or vessels.

4.2. Emission Data and Emissions Factors

4.2.1 Summary of Major Studies and Emission Factors

Given the potential for significant emissions from completions and recompletions, there have been numerous recent studies conducted to estimate these emissions. In the evaluation of the emissions and emission reduction options for completions and recompletions, many of these studies were consulted. Table 4-1 presents a list of the studies consulted along with an indication of the type of information contained in the study.

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Documents [3]	EPA	2010	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008 [4,5]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry [6, 7, 8, 9]	Gas Research Institute /US Environmental Protection Agency	1996	Nationwide	X	X
Methane Emissions from the US Petroleum Industry (Draft) [10]	EPA	1996	Nationwide	X	
Methane Emissions from the US Petroleum Industry [11]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [12]	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories [13]	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State[14]	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements [15]	Environmental Defense Fund	2009	Regional	X	X
Emissions from Oil and Natural Gas Production Facilities [16]	Texas Commission for Environmental Quality	2007	Regional	X	X
Availability, Economics and Production of North American Unconventional Natural Gas Supplies 1	Interstate Natural Gas Association of America	2008	Nationwide		

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor(s)	Emission Information	Control Information
Petroleum and Natural Gas Statistical Data[17]	U.S. Energy Information Administration	2007-2009	Nationwide		
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations [18]	EPA	1999		X	
Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program [19]	New York State Department of Environmental Conservation	2009	Regional	X	X
Natural Gas STAR Program [20, 21, 22, 23, 24, 25]	EPA	2000-2010	Nationwide/ Regional	X	X

4.2.2 Representative Completion and Recompletion Emissions

As previously mentioned, one specific emission source during completion and recompletion 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 the completion of a new well or during recompletion activities that involve re-drilling or re-fracturing of an existing well. For this analysis, well completion and recompletion emissions are estimated as the venting of emissions from the well during the initial phases of well preparation or during recompletion maintenance and/or re-fracturing of an existing well.

As previously stated, this analysis assumes wells completed/recompleted with hydraulic fracturing are found in tight sand, shale, or coal bed methane formations. A majority of the available emissions data for recompletions is for vertically drilled wells. It is projected that in the future, a majority of completions and recompletions will predominantly be performed on horizontal wells. However, there is not enough history of horizontally drilled wells to make a reasonable estimation of the difference in emissions from recompletions of horizontal versus vertical wells. Therefore, for this analysis, no distinction was made between vertical and horizontal wells.

As shown in Table 4-1, methane emissions from oil and natural gas operations have been measured, analyzed and reported in studies spanning the past few decades. The basic approach for this analysis was to approximate methane emissions from representative oil and gas completions and recompletions and then estimate volatile organic compounds (VOC) and hazardous air pollutants (HAP) using a representative gas composition.[26] The specific gas composition ratios used for gas wells were 0.1459 pounds (lb) VOC per lb methane (lb VOC/lb methane) and 0.0106 lb HAP/lb methane. The specific gas composition ratios used for oil wells were 0.8374 pounds lb VOC/lb methane and 0.0001 lb HAP/lb methane.

The EPA's analysis to estimate methane emissions conducted in support of the Greenhouse Gas Mandatory Reporting Rule (Subpart W), which was published in the *Federal Register* on November 30, 2010 (75 FR 74458), was the foundation for methane emission estimates from natural gas completions with hydraulic fracturing and recompletions with hydraulic fracturing. Methane emissions from oil well completions, oil well recompletions, natural gas completions without hydraulic fracturing, and natural gas recompletions without hydraulic fracturing were derived directly from the EPA's Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008 (Inventory).[4] A summary of emissions for a representative model well completion or recompletion is found in Table 4-2.

Table 4-2. Uncontrolled Emissions Estimates from Oil and Natural Gas Well Completions and Recompletions

Well Completion Category	Emissions (Mcf/event)	Emissions (tons/event)		
	Methane	Methane[a]	VOC[b]	HAP[c]
Natural Gas Well Completion without Hydraulic Fracturing	38.6	0.8038	0.12	0.009
Natural Gas Well Completion with Hydraulic Fracturing	7,623	158.55	23.13	1.68
Oil Well Completions	0.34	0.0076	0.00071	0.0000006
Natural Gas Well Recompletion without Hydraulic Fracturing	2.59	0.0538	0.0079	0.0006
Natural Gas Well Recompletion with Hydraulic Fracturing	7,623	158.55	23.13	1.68
Oil Well Recompletions	0.057	0.00126	0.001	0.0000001

Minor discrepancies may exist due to rounding.

a. Reference 4, Appendix B., pgs 84-89. The conversion used to convert methane from volume to weight is 0.0208 tons methane is equal to 1 Mcf of methane. It is assumed methane comprises 83.081 percent by volume of natural gas from gas wells and 46.732 percent by volume of methane from oil wells.
b. Assumes 0.1459 lb VOC /lb methane for natural gas wells and 0.8374 lb VOC/lb methane for oil wells.
c. Assumes 0.0106 lb HAP/lb methane for natural gas wells and 0.0001 lb HAP/lb methane for oil wells.

4.3 Nationwide Emissions from New Sources

4.3.1 Overview of Approach

The first step in this analysis is to estimate nationwide emissions in absence of the proposed rulemaking, referred to as the baseline emissions estimate. In order to develop the baseline emissions estimate, the number of completions and recompletions performed in a typical year was estimated and then multiplied by the expected uncontrolled emissions per well completion listed in Table 4-2. In addition, to ensure no emission reduction credit was attributed to sources already controlled under State regulations, it was necessary to account for the number of completions/recompletions already subject to State regulations as detailed below. In order to estimate the number of wells that are already controlled under State regulations, existing well data was analyzed to estimate the percentage of currently controlled wells. This percentage was assumed to also represent the wells that would have been controlled in absence of a federal regulation and applied to the number of well completions estimated for future years.

4.3.2 Number of Completions and Recompletions

The number of new well completions was estimated using the National Energy Modeling System (NEMS). NEMS is a model of U.S. energy economy developed and maintained by the Energy Information Administration (EIA). 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. EIA is legally required to make the NEMS 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 NEMS, 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.

New well completion estimates are based on predictions from the NEMS Oil and Gas Supply Model, drawing upon the same assumptions and model used in the Annual Energy Outlook 2011 Reference Case. New well completions estimates were based on total successful wells drilled in 2015 (the year of analysis for regulatory impacts) for the following well categories: natural gas completions without hydraulic fracturing, natural gas completions with hydraulic fracturing, and oil well completions.

Successful wells are assumed to be equivalent to completed wells. Meanwhile, it was assumed that new dry wells would be abandoned and shut in and would not be completed. Therefore estimates of the number of dry wells were not included in the activity projections or impacts discussion for exploratory and developmental wells. Completion estimates are based on successful developmental and exploratory wells for each category defined in NEMS that includes oil completions, conventional gas completions and unconventional gas completions. The NEMS database defines unconventional reservoirs as those in shale, tight sand, and coalbed methane formations and distinguishes those from wells drilled in conventional reservoirs. Since hydraulic fracturing is most common in unconventional formations, this analysis assumes new successful natural gas wells in shale, tight sand, and coalbed methane formations are completed with hydraulic fracturing. New successful natural gas wells in conventional formations are assumed to be completed without hydraulic fracturing.

The number of natural gas recompletions with hydraulic fracturing (also referred to as a re-fracture), natural gas recompletions without hydraulic fracturing and oil well recompletions was based on well count data found in the HPDI® database.[ii, iii] The HPDI database consists of oil and natural gas well information maintained by a private organization that provides parameters describing the location, operator, and production characteristics. HPDI® collects information on a well basis such as the operator, state, basin, field, annual gas production, annual oil production, well depth, and shut-in pressure, all of which is aggregated from operator reports to state governments. HPDI was used to estimate the number of recompleted wells because the historical well data from HPDI is a comprehensive resource describing existing wells. Well data from 2008 was used as a base year since it was the most recent available data at the time of this analysis and is assumed to represent the number of recompletions that would occur in a representative year. The number of hydraulically fractured natural gas recompletions was estimated by estimating each operator and field combination found in the HPDI database and multiplying by 0.1 to represent 10 percent of the wells being re-fractured annually (as assumed in Subpart W's Technical Supporting Document3). This results in 14,177 total natural gas recompletions with hydraulic fracturing in the U.S. for the year 2008; which is assumed to depict a representative year. Non-fractured

[ii] HPDI, LLC is a private organization specializing in oil and gas data and statistical analysis. The HPDI database is focused on historical oil and gas production data and drilling permit data.
[iii] For the State of Pennsylvania, the most recent drilling information available from HPDI was for 2003. Due to the growth of oil and gas operations occurring in the Marcellus region in Pennsylvania, this information would not accurately represent the size of the industry in Pennsylvania for 2006 through 2008. Therefore, information from the Pennsylvania's Department of Environmental Protection was used to estimate well completion activities for this region. Well data from remaining states were based on available information from HPDI. From
<http://www.marcellusreporting.state.pa.us/OGREReports/Modules/DataExports/DataExports.aspx

recompletions were based on well data for 2008 in HPDI. The number of estimated well completions and recompletions for each well source category is listed in Table 4-3.

<u>4.3.3 Level of Controlled Sources in Absence of Federal Regulation</u>

As stated previously, to determine the impact of a regulation, it is first necessary to determine the current level of emissions from the sources being evaluated, or baseline emissions. To more accurately estimate baseline emissions for this analysis, and to ensure no emission reduction credit was attributed for sources already being controlled, it was necessary to evaluate the number of completions and recompletions already subject to regulation. Therefore, the number of completions and recompletions already being controlled in the absence of federal regulation was estimated based on the existing State regulations that require control measures for completions and recompletions. Although there may be regulations issued by other local ordinances for cities and counties throughout the U.S., wells impacted by these regulations were not included in this analysis because well count data are not available on a county or local ordinance level. Therefore, the percentage calculated based on the identified State regulations should be considered a conservative estimate.

In order to determine the number of completions and recompletions that are already controlled under State regulations, EIA historical well count data was analyzed to determine the percentage of new wells currently undergoing completion and recompletion in the States identified as having existing controls.[iv] Colorado (CO) and Wyoming (WY) were the only States identified as requiring controls on completions prior to NSPS review. The State of Wyoming's Air Quality Division (WAQD) requires operators to complete wells without flaring or venting where the following criteria are met: (1) the flowback gas meets sales line specifications and (2) the pressure of the reservoir is high enough to enable REC. If the above criteria are not met, then the produced gas is to be flared. [27] The WAQD requires that, "emissions of VOC and HAP associated with the flaring and venting of hydrocarbon fluids (liquids and gas) associated with well completion and recompletion activities shall be eliminated to the extent practicable by routing the recovered liquids into storage tanks and routing the recovered gas into a gas sales line or collection system." Similar to WY, the Colorado Oil and Gas Conservation Commission (COOGCC) requires REC for both oil and natural gas wells.[28] It was assumed for this analysis that the ratio of natural wells in CO and WY to the total number of wells in the U.S. represents the percentage of controlled wells for well completions. The ratio of wells in WY to the number of total nationwide wells

[iv] See EIA's The Number of Producing Wells, http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm

Table 4-3: Estimated Number of Total Oil and Natural Gas Completions and Recompletions for a Typical Year

Well Completion Category	Estimated Number of Total Completions and Recompletions[a]	Estimated Number of Controlled Completions and Recompletions	Estimated Number of Uncontrolled Completions and Recompletions[b]
Natural Gas Well Completions without Hydraulic Fracturing*	7,694		7,694
Exploratory Natural Gas Well Completions with Hydraulic Fracturing**	446		446
Developmental Natural Gas Well Completions with Hydraulic Fracturing[c]	10,957	1,644	9,313
Oil Well Completions[d]	12,193		12,193
Natural Gas Well Recompletions without Hydraulic Fracturing	42,342		42,342
Natural Gas Well Recompletions with Hydraulic Fracturing‡‡	14,177	2,127	12,050
Oil Well Recompletions‡	39,375		39,375

a. Natural gas completions and recompletions without hydraulic fracturing are assumed to be uncontrolled at baseline.
b. Fifteen percent of natural gas well completions with hydraulic fracturing are assumed as controlled at baseline.
c. Oil well completions and recompletions are assumed to be uncontrolled at baseline.
d. Fifteen percent of natural gas well recompletions with hydraulic fracturing are assumed to be controlled at baseline.

was assumed to represent the percentage of controlled well recompletions as it was the only State identified as having regulations directly regulated to recompletions.

From this review it was estimated that 15 percent of completions and 15 percent of recompletions are controlled in absence of federal regulation. It is also assumed for this analysis that only natural gas wells undergoing completion or recompletion with hydraulic fracturing are controlled in these States. Completions and recompletions that are performed without hydraulic fracturing, in addition to oil well completions and recompletions were assumed to not be subject to State regulations and therefore, were assumed to not be regulated at baseline. Baseline emissions for the controlled completions and recompletions covered by regulations are assumed to be reduced by 95 percent from the use of both REC and combustion devices that may be used separately or in tandem, depending on the individual State regulation.[v] The final activity factors for uncontrolled completions and uncontrolled recompletions are also listed in Table 4-3.

4.3.4 Emission Estimates

Using the estimated emissions, number of uncontrolled and controlled wells at baseline, described above, nationwide emission estimates for oil and gas well completions and recompletions in a typical year were calculated and are summarized in Table 4-4. All values have been independently rounded to the nearest ton for estimation purposes. As the table indicates, hydraulic fracturing significantly increases the magnitude of emissions. Completions and recompletions without hydraulic fracturing have lower emissions, while oil completions and recompletions have even lower emissions in comparison.

4.4 Control Techniques

4.4.1 Potential Control Techniques

Two techniques were considered that have been proven to reduce emissions from well completions and recompletions: REC and completion combustion. One of these techniques, REC, is an approach that not only reduces emissions but delivers natural gas product to the sales meter that would typically be vented. The second technique, completion combustion, destroys the organic compounds. Both of these techniques are discussed in the following sections, along with estimates of the impacts of their application for a representative well. Nationwide impacts of chosen regulatory options are discussed in

[v] Percentage of controls by flares versus REC were not determined, so therefore, the count of controlled wells with REC versus controlled wells with flares was not determined and no secondary baseline emission impacts were calculated.

Table 4-4. Nationwide Baseline Emissions from Uncontrolled Oil and Gas Well Completions and Recompletions

Well Completion Category	Uncontrolled Methane Emissions per event (tpy)	Number of Uncontrolled Wells[a]	Baseline Nationwide Emissions (tons/year)[a]		
			Methane[b]	VOC[c]	HAP[d]
Natural Gas Well Completions without Hydraulic Fracturing	0.8038	7,694	6,185	902	66
Exploratory Natural Gas Well Completions with Hydraulic Fracturing	158.55	446	70,714	10,317	750
Developmental Natural Gas Well Completions with Hydraulic Fracturing	158.55	9,313	1,476,664	215,445	15,653
Oil Well Completions	0.0076	12,193	93	87	.008
Natural Gas Well Recompletions without Hydraulic Fracturing	0.0538	42,342	2,279	332	24
Natural Gas Well Recompletions with Hydraulic Fracturing	158.55	12,050	1,910,549	278,749	20,252
Oil Well Recompletions	0.00126	39,375	50	47	.004

Minor discrepancies may be due to rounding.

a. Baseline emissions include emissions from uncontrolled wells plus five percent of emissions from controlled sources. The Baseline emission reductions listed in the Regulatory Impacts (Table 4-9) represents only emission reductions from uncontrolled sources.
b. The number of controlled and uncontrolled wells estimated based on State regulations.
c. Based on the assumption that VOC content is 0.1459 pounds VOC per pound methane for natural gas wells and 0.8374 pounds VOC per pound methane for oil wells This estimate accounts for 5 percent of emissions assumed as vented even when controlled. Does not account for secondary emissions from portion of gas that is directed to a combustion device.
d. Based on the assumption that HAP content is 0.0106 pounds HAP per pound methane for natural gas wells and 0.0001 pounds HAP per pound methane for oil wells. This estimate accounts for 5 percent of emissions assumed as vented even when controlled. Does not account for secondary emissions from portion of gas that is directed to a combustion device.

section 4.5.

4.4.2 Reduced Emission Completions and Recompletions

4.4.2.1 Description

Reduced emission completions, also referred to as "green" or "flareless" completions, use specially designed equipment at the well site to capture and treat gas so it can be directed to the sales line. This process prevents some natural gas from venting and results in additional economic benefit from the sale of captured gas and, if present, gas condensate. Additional equipment required to conduct a REC may include additional tankage, special gas-liquid-sand separator traps, and a gas dehydrator.[29] In many cases, portable equipment used for RECs operate in tandem with the permanent equipment that will remain after well drilling is completed. In other instances, permanent equipment is designed (e.g. oversized) to specifically accommodate initial flowback. Some limitations exist for performing RECs since technical barriers fluctuate from well to well. Three main limitations include the following for RECs:

- Proximity of pipelines. For exploratory wells, no nearby sales line may exist. The lack of a nearby sales line incurs higher capital outlay risk for exploration and production companies and/or pipeline companies constructing lines in exploratory fields. The State of Wyoming has set a precedent by stating proximity to gathering lines for wells is not a sufficient excuse to avoid RECs unless they are deemed exploratory, or the first well drilled in an area that has never had oil and gas well production prior to that drilling instance (i.e., a wildcat well).[30] In instances where formations are stacked vertically and horizontal drilling could take place, it may be possible that existing surface REC equipment may be located near an exploratory well, which would allow for a REC.

- Pressure of produced gas. During each stage of the completion/recompletion process, the pressure of flowback fluids may not be sufficient to overcome the sales line backpressure. This pressure is dependent on the specific sales line pressure and can be highly variable. In this case, combustion of flowback gas is one option, either for the duration of the flowback or until a point during flowback when the pressure increases to flow to the sales line. Another control option is compressor applications. One application is gas lift which is accomplished by withdrawing gas from the sales line, boosting its pressure, and routing it down the well casing to push the fracture fluids up the tubing. The increased pressure facilitates flow into the separator and then the sales line where the lift gas becomes part of the normal flowback that can be recovered during a REC. Another potential compressor application is to boost pressure of the flowback gas after it exits the separator. This technique is experimental because of the difficulty operating a compressor on widely fluctuating flowback rate.

- Inert gas concentration. If the concentration of inert gas, such as nitrogen or carbon dioxide, in the flowback gas exceeds sales line concentration limits, venting or combustion of the flowback may be necessary for the duration of flowback or until the gas energy content increases to allow flow to the sales line. Further, since the energy content of the flowback gas may not be high enough to sustain a flame due to the presence of the inert gases, combustion of the flowback stream would require a continuous ignition source with its own separate fuel supply.

4.4.2.2. Effectiveness

RECs are an effective emissions reduction method for only natural gas completions and recompletions performed with hydraulic fracturing based on the estimated flowback emissions described in Section 4.2. The emissions reductions vary according to reservoir characteristics and other parameters including length of completion, number of fractured zones, pressure, gas composition, and fracturing technology/technique. Based on several experiences presented at Natural Gas STAR technology transfer workshops, this analysis assumes 90 percent of flowback gas can be recovered during a REC.[31] Any amount of gas that cannot be recovered can be directed to a completion combustion device in order to achieve a minimum 95 percent reduction in emissions.

4.4.2.3 Cost Impacts

All completions incur some costs to a company. Performing a REC will add to these costs. Equipment costs associated with RECs vary from well to well. High production rates may require larger equipment to perform the REC and will increase costs. If permanent equipment, such as a glycol dehydrator, is already installed or is planned to be in place at the well site as normal operations, costs may be reduced as this equipment can be used or resized rather than installing a portable dehydrator for temporary use during the completion. Some operators normally install equipment used in RECs, such as sand traps and three-phase separators, further reducing incremental REC costs.

Costs of performing a REC are projected to be between $700 and $6,500 per day, with representative well completion flowback lasting 3 to 10 days.2 This cost range is the incremental cost of performing a REC over a traditional completion, where typically the gas is vented or combusted because there is an absence of REC equipment. Since RECs involve techniques and technologies that are new and continually evolving, and these cost estimates are based on the state of the industry in 2006 (adjusted to 2008 US dollars). [vi] Cost data used in this analysis are qualified below:

- $700 per day (equivalent to $806 per day in 2008 dollars) represents completion and recompletion costs where key pieces of equipment, such as a dehydrator or three phase separator, are already found on site and are of suitable design and capacity for use during flowback.

- $6,500 per day (equivalent to $7,486 in 2008 dollars) represents situations where key pieces of equipment, such as a dehydrator or three-phase separator, are temporarily brought on site and then relocated after the completion.

Costs were assessed based on an average of the above data (for costs and number of days per completion), resulting in an average incremental cost for a REC of $4,146 per day (2008 dollars) for an average of 7 days per completion. This results in an overall incremental cost of $29,022 for a REC versus an uncontrolled completion. An additional $691 (2008 dollars) was included to account for transportation and placement of equipment, bringing total incremental costs estimated at $29,713. Reduced emission completions are considered one-time events per well; therefore annual costs were conservatively assumed to be the same as capital costs. Dividing by the expected emission reductions, cost-effectiveness for VOC is $1,429 per ton, with a methane co-benefit of $208 per ton. Table 4-5 provides a summary of REC cost-effectiveness.

Monetary savings associated with additional gas captured to the sales line was also estimated based on a natural gas price of $4.00[vii] per thousand cubic feet (Mcf).[32] It was assumed that all gas captured would be included as sales gas. Therefore, assuming that 90 percent of the gas is captured and sold, this equates

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[vi] The Chemical Engineering Cost Index was used to convert dollar years. For REC, the 2008 value equals 575.4 and the 2006 value equals 499.6.

[vii] The average market price for natural gas in 2010 was approximately $4.16 per Mcf. This is much less compared to the average price in 2008 of $7.96 per Mcf. Due to the volatility in the price, a conservative savings of $4.00 per Mcf estimate was projected for the analysis in order to not overstate savings. The value of natural gas condensate recovered during the REC would also be significant depending on the gas composition. This value was not incorporated into the monetary savings in order to not overstate savings.

Table 4-5. Reduced Emission Completion and Recompletion Emission Reductions and Cost Impacts Summary

Well Completion Category	Emission Reduction Per Completion/Recompletion (tons/year)[a]			Total Cost Per Completion/ Recompletion[b] ($/event)	VOC Cost Effectiveness ($/ton)[c]		Methane Cost Effectiveness ($/ton)	
	VOC	Methane	HAP		without savings	with savings	without savings	with savings
Natural Gas Completions and Recompletions with Hydraulic Fracturing	20.8	142.7	1.5	29,713	1,429	net savings	208	net savings

Minor discrepancies may be due to rounding.

a. This represents a ninety percent reduction from baseline for the average well.
b. Total cost for reduced emission completion is expressed in terms of incremental cost versus a completion that vents emissions. This is based on an average incremental cost of $4,146 per day for an average length of completion flowback lasting 7 days and an additional $691 for transportation and set up.
c. Cost effectiveness has been rounded to the nearest dollar.

to a total recovery of 8,258 Mcf of natural gas per completion or recompletion with hydraulic fracturing. The estimated value of the recovered natural gas for a representative natural gas well with hydraulic fracturing is approximately $33,030. In addition we estimate an average of 34 barrels of condensate is recovered per completion or recompletion. Assuming a condensate value of $70 per barrel (bbl), this result is an income due to condensate sales around $2,380.[33] When considering these savings from REC, for a completion or recompletion with hydraulic fracturing, there is a net savings on the order of $5,697 per completion.

4.4.2.4 Secondary Impacts

A REC is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., nitrogen oxides, particulate matter, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to REC.

4.4.3 Completion Combustion Devices

4.4.3.1 Description

Completion combustion is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.[34] Completion combustion devices are used to control VOC in many industrial settings, since the completion combustion device can normally handle fluctuations in concentration, flow rate, heating value, and inert species content.[35] Completion combustion devices commonly found on drilling sites are rather crude and portable, often installed horizontally due to the liquids that accompany the flowback gas. These flares can be as simple as a pipe with a basic ignition mechanism and discharge over a pit near the wellhead. However, the flow directed to a completion combustion device may or may not be combustible depending on the inert gas composition of flowback gas, which would require a continuous ignition source. Sometimes referred to as pit flares, these types of combustion devices do not employ an actual control device, and are not capable of being tested or monitored for efficiency. They do provide a means of minimizing vented gas and is preferable to venting. For the purpose of this analysis, the term completion combustion device represents all types of combustion devices including pit flares.

4.4.3.2 Effectiveness

The efficiency of completion combustion devices, or exploration and production flares, can be expected to achieve 95 percent, on average, over the duration of the completion or recompletion. If the energy content of natural gas is low, then the combustion mechanism can be extinguished by the flowback gas. Therefore, it is more reliable to install an igniter fueled by a consistent and continuous ignition source. This scenario would be especially true for energized fractures where the initial flowback concentration will be extremely high in inert gases. This analysis assumes use of a continuous ignition source with an independent external fuel supply is assumed to achieve an average of 95 percent control over the entire flowback period. Additionally, because of the nature of the flowback (i.e., with periods of water, condensate, and gas in slug flow), conveying the entire portion of this stream to a flare or other control device is not always feasible. Because of the exposed flame, open pit flaring can present a fire hazard or other undesirable impacts in some situations (e.g., dry, windy conditions, proximity to residences, etc.). As a result, we are aware that owners and operators may not be able to flare unrecoverable gas safely in every case.

Federal regulations require industrial flares meet a combustion efficiency of 98 percent or higher as outlined in 40 CFR 60.18. This statute does not apply to completion combustion devices. Concerns have been raised on applicability of 40 CFR 60.18 within the oil and gas industry including for the production segment.[30, 36, 37] The design and nature of completion combustion devices must handle multiphase flow and stream compositions that vary during the flowback period. Thus, the applicability criterion that specifies conditions for flares used in highly industrial settings may not be appropriate for flares typically used to control emissions from well completions and recompletions.

4.4.3.3 Cost Impacts

An analysis depicting the cost for wells including completion combustion devices was conducted for the Petroleum Services Association of Canada (PSAC) [38] in 2009 by N.L. Fisher Supervision and Engineering, Ltd.[viii] The data corresponds to 34 gas wells for various types of formations, including coal bed methane and shale. Multiple completion methods were also examined in the study including hydraulic and energized fracturing. Using the cost data points from these natural gas well completions,

[viii] It is important to note that outliers were excluded from the average cost calculation. Some outliers estimated the cost of production flares to be as low as $0 and as high as $56,000. It is expected that these values are not representative of typical flare costs and were removed from the data set. All cost data found in the PSAC study were aggregated values of the cost of production flares and other equipment such as tanks. It is possible the inclusion of the other equipment is not only responsible for the outliers, but also provides a conservatively high estimate for completion flares.

an average completion combustion device cost is approximately $3,523 (2008 dollars).[ix] As with the REC, because completion combustion devices are purchased for these one-time events, annual costs were conservatively assumed to be equal to the capital costs.

It is assumed that the cost of a continuous ignition source is included in the combustion completion device cost estimations. It is understood that multiple completions and recompletions can be controlled with the same completion combustion device, not only for the lifetime of the combustion device but within the same yearly time period. However, to be conservative, costs were estimated as the total cost of the completion combustion device itself, which corresponds to the assumption that only one device will control one completion per year. The cost impacts of using a completion combustion device to reduce emissions from representative completions/recompletions are provided in Table 4-6. Completion combustion devices have a cost-effectiveness of $161 per ton VOC and a co-benefit of $23 per ton methane for completions and recompletions with hydraulic fracturing.

4.4.3.4 Secondary Impacts

Noise and heat are the two primary undesirable outcomes of completion combustion device operation. In addition, combustion and partial combustion of many pollutants also create secondary pollutants including nitrogen oxides (NO_x), carbon monoxide (CO), sulfur oxides (SO_x, carbon dioxide (CO_2), and smoke/particulates (PM). The degree of combustion depends on the rate and extent of fuel mixing with air and the temperature maintained by the flame. Most hydrocarbons with carbon-to-hydrogen ratios greater than 0.33 are likely to smoke.[34] Due to the high methane content of the gas stream routed to the completion combustion device, it suggests that there should not be smoke except in specific circumstances (e.g., energized fractures). The stream to be combusted may also contain liquids and solids that will also affect the potential for smoke. Soot can typically be eliminated by adding steam. Based on current industry trends in the design of completion combustion devices and in the decentralized nature of completions, virtually no completion combustion devices include steam assistance.[34]

Reliable data for emission factors from flare operations during natural gas well completions are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing

[ix] The Chemical Engineering Cost Index was used to convert dollar years. For the combustion device the 2009 value equals 521.9. The 2009 average value for the combustion device is $3,195.

Table 4-6. Emission Reduction and Cost-effectiveness Summary for Completion Combustion Devices

Well Completion Category	Emission Reduction Per Completion/Workover (tons/year)[a]			Total Capital Cost Per Completion Event ($)*	VOC Cost Effectiveness	Methane Cost Effectiveness
	VOC	Methane	HAP		($/ton)[b]	($/ton)
Natural Gas Well Completions without Hydraulic Fracturing	0.11	0.76	0.0081	3,523	31,619	4,613
Natural Gas Well Completions with Hydraulic Fracturing	21.9	150.6	1.597		160	23
Oil Well Completions	0.01	0.007	0.0000007		520,580	488,557
Natural Gas Well Recompletions without Hydraulic Fracturing	0.007	0.051	0.0005		472,227	68,889
Natural Gas Well Recompletions with Hydraulic Fracturing	21.9	150.6	1.597		160	23
Oil Well Recompletions	0.00	0.001	0.0000001		3,134,431	2,941,615

Minor discrepancies may be due to rounding.

a. This assumes one combustion device will control one completion event per year. This should be considered a conservative estimate, since it is likely multiple completion events will be controlled with the same combustion unit in any given year. Costs are stated in 2008 dollars.

80 percent propylene and 20 percent propane.[34] These emissions factors, however, are the best indication for secondary pollutants from flare operations currently available. These secondary emission factors are provided are provided in Table 4-7.

Since this analysis assumed pit flares achieve 95 percent efficiency over the duration of flowback, it is likely the secondary emission estimations are lower than actuality (i.e. AP-42 assumes 98 percent efficiency). In addition due, to the potential for the incomplete combustion of natural gas across the pit flare plume, the likelihood of additional NO_x formulating is also likely. The degree of combustion is variable and depends on the on the rate and extent of fuel mixing with air and on the flame temperature. Moreover, the actual NO_x (and CO) emissions may be greatly affected when the raw gas contains hydrocarbon liquids and water. For these reasons, the nationwide impacts of combustion devices discussed in Section 4.5 should be considered minimum estimates of secondary emissions from combustion devices.

4.5 Regulatory Options

The REC pollution prevention approach would not result in emissions of CO, NO_x, and PM from the combustion of the completion gases in the flare, and would therefore be the preferred option. As discussed above, REC is only an option for reducing emissions from gas well completions/workovers with hydraulic fracturing. Taking this into consideration, the following regulatory alternatives were evaluated:

- Regulatory Option 1: Require completion combustion devices for conventional natural gas well completions and recompletions;
- Regulatory Option 2: Require completion combustion devices for oil well completions and recompletions;
- Regulatory Option 3: Require combustion devices for all completions and recompletions;
- Regulatory Option 4: Require REC for all completions and recompletions of hydraulically fractured wells;
- Regulatory Option 5: Require REC and combustion operational standards for natural gas well completions with hydraulic fracturing, with the exception of exploratory, and delineation wells;
- Regulatory Option 6: Require combustion operational standards for exploratory and delineation wells; and

Table 4-7. Emission Factors from Flare Operations from AP-42 Guidelines Table 13.4-1[a]

Pollutant	Emission Factor ($lb/10^6$ Btu)
Total Hydrocarbon[b]	0.14
Carbon Monoxide	0.37
Nitrogen Oxides	0.068
Particular Matter[c]	0-274
Carbon Dioxide[d]	60

a. Based on combustion efficiency of 98 percent.
b. Measured as methane equivalent.
c. Soot in concentration values: nonsmoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.
d. Carbon dioxide is measured in kg CO2/MMBtu and is derived from the carbon dioxide emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

- Regulatory Option 7: Require REC and combustion operational standards for all natural gas well recompletions with hydraulic fracturing.

The following sections discuss these regulatory options.

4.5.1 Evaluation of Regulatory Options

The first two regulatory options (completion combustion devices for conventional natural gas well completions and recompletions and completion combustion devices for oil well completions and recompletions) were evaluated first. As shown in Table 4-6, the cost effectiveness associated with controlling conventional natural gas and oil well completions and recompletions ranges from $31,600 per ton VOC to over $3.7 million per ton VOC. Therefore, Regulatory Options 1 and 2 were rejected due to the high cost effectiveness.

The next regulatory option, to require completion combustion devices for all completions and recompletions, was considered. Under Regulatory Option 3, all of the natural gas emitted from the well during flowback would be destroyed by sending flowback gas through a combustion unit. Not only would this regulatory option result in the destruction of a natural resource with no recovery of salable gas, it also would result in an increase in emissions of secondary pollutants (e.g., nitrogen oxides, carbon monoxide, etc.). Therefore, Regulatory Option 3 was also rejected.

The fourth regulatory option would require RECs for all completions and recompletions of hydraulically fractured wells. As stated previously, RECs are not feasible for all well completions, such as exploratory wells, due to their distance from sales lines, etc. Further, RECs are also not technically feasible for each well at all times during completion and recompletion activities due to the variability of the pressure of produced gas and/or inert gas concentrations. Therefore, Regulatory Option 4 was rejected.

The fifth regulatory option was to require an operational standard consisting of a combination of REC and combustion for natural gas well completions with hydraulic fracturing. As discussed for Regulatory Option 4, RECs are not feasible for every well at all times during completion or recompletion activities due to variability of produced gas pressure and/or inert gas concentrations. In order to allow for wellhead owners and operators to continue to reduce emissions when RECs are not feasible due to well characteristics (e.g, wellhead pressure or inert gas concentrations), Regulatory Option 5 also allows for the use of a completion combustion device in combination with RECs.

Under Regulatory Option 5, a numerical limit was considered, but was rejected in favor of an operational standard. Under section 111(h)(2) of the CAA, EPA can set an operational standard which represents the best system of continuous emission reduction, provided the following criteria are met:

> "(A) a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or
>
> (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations."

As discussed in section 4.4.3, emissions from a completion combustion device cannot be measured or monitored to determine efficiency making an operational standard appropriate. Therefore, an operational standard under this regulatory option consists of a combination of REC and a completion combustion device to minimize the venting of natural gas and condensate vapors to the atmosphere, but allows venting in lieu of combustion for situations in which combustion would present safety hazards, other concerns, or for periods when the flowback gas is noncombustible due to high concentrations of inert gases. Sources would also be required, under this regulatory option, to maintain documentation of the overall duration of the completion event, duration of recovery using REC, duration of combustion, duration of venting, and specific reasons for venting in lieu of combustion. It was also evaluated whether Regulatory Option 5 should apply to all well completions, including exploratory and delineation wells.

As discussed previously, one of the technical limitations of RECs is that they are not feasible for use at some wells due to their proximity to pipelines. Section 111(b)(2) of the CAA allows EPA to "…distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing…." performance standards. Due to their distance from sales lines, and the relatively unknown characteristics of the formation, completion activities occurring at exploratory or delineation wells were considered to be a different "type" of activity than the types of completion activities occurring at all other gas wells. Therefore, two subcategories of completions were identified: *Subcategory 1* wells are all natural gas wells completed with hydraulic fracturing that do not fit the definition of exploratory or delineation wells. *Subcategory 2* wells are natural gas wells that meet the following definitions of exploratory or delineation wells:

- Exploratory wells are wells outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists or

- Delineation wells means a well drilled in order to determine the boundary of a field or producing reservoir.

Based on this subcategorization, Regulatory Option 5 would apply to the Subcategory 1 wells and a sixth regulatory option was developed for Subcategory 2 wells.

Regulatory Option 6 requires an operational standard for combustion for the Subcategory 2 wells. As described above, REC is not an option for exploratory and delineation wells due to their distance from sales lines. As with the Regulatory Option 5, a numerical limitation is not feasible. Therefore, this regulatory option requires an operational standard where emissions are minimized using a completion combustion device during completion activities at Subcategory 2 wells, with an allowance for venting in situations where combustion presents safety hazards or other concerns or for periods when the flowback gas is noncombustible due to high concentrations of inert gases. Consistent with Regulatory Option 5, records would be required to document the overall duration of the completion event, the duration of combustion, the duration of venting, and specific reasons for venting in lieu of combustion.

The final regulatory option was considered for recompletions. Regulatory Option 7 requires an operational standard for a combination of REC and a completion combustion device for all recompletions with hydraulic fracturing performed on new and existing natural gas wells. Regulatory Option 7 has the same requirements as Regulatory Option 5. Subcategorization similar to Regulatory Option 5 was not necessary for recompletions because it was assumed that RECs would be technically feasible for recompletions at all types of wells since they occur at wells that are producing and thus proximity to a sales line is not an issue. While evaluating this regulatory option, it was considered whether or not recompletions at existing wells should be considered modifications and subject to standards.

The affected facility under the New Source Performance Standards (NSPS) is considered to be the wellhead. Therefore, a new well drilled after the proposal date of the NSPS would be subject to emission control requirements. Likewise, wells drilled prior to the proposal date of the NSPS would not be subject to emission control requirements unless they underwent a modification after the proposal date. Under section 111(a) of the Clean Air Act, the term "modification" means:

> "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted."

The wellhead is defined as the piping, casing, tubing, and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. In order to fracture an existing well during recompletion, the well would be re-perforated, causing physical change to the wellbore and casing and therefore a physical change to the wellhead, the affected facility. Additionally, much of the emissions data on which this analysis is based demonstrates that hydraulic fracturing results in an increase in emissions. Thus, recompletions using hydraulic fracturing result in an increase in emissions from the existing well producing operations. Based on this understanding of the work performed in order to recomplete the well, it was determined that a recompletion would be considered a modification under CAA section 111(a) and thus, would constitute a new wellhead affected facility subject to NSPS. Therefore, Regulatory Option 7 applies to recompletions using hydraulic fracturing at new and existing wells.

In summary, Regulatory Options 1, 2, 3, and 4 were determined to be unreasonable due to cost considerations, other impacts or technical feasibility and thereby rejected. Regulatory Options 5, 6, and 7 were determined to be applicable to natural gas wells and were evaluated further.

4.5.2 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to Regulatory Options 5, 6, and 7 which were selected as viable options for setting standards for completions and recompletions.

4.5.2.1 Primary Environmental Impacts of Regulatory Options

Regulatory Options 5, 6, and 7 were selected as options for setting standards for completions and regulatory options as follows:

- Regulatory Option 5: Operational standard for completions with hydraulic fracturing for Subcategory 1 wells (i.e., wells which do not meet the definition of exploratory or delineation wells), which requires a combination of REC with combustion, but allows for venting during specified situations.

- Regulatory Option 6: An operational standard for completions with hydraulic fracturing for exploratory and delineation wells (i.e., Subcategory 2 wells) which requires completion combustion devices with an allowance for venting during specified situations.

- Regulatory Option 7: An operational standard equivalent to Regulatory Option 5 which applies to recompletions with hydraulic fracturing at new and existing wells.

The number of completions and recompletions that would be subject to the regulatory options listed above was presented in Table 4-3. It was estimated that there would be 9,313 uncontrolled developmental natural gas well completions with hydraulic fracturing subject to Regulatory Option 5. Regulatory Option 6 would apply to 446 uncontrolled exploratory natural gas well completions with hydraulic fracturing, and 12,050 uncontrolled recompletions at existing wells would be subject to Regulatory Option 7.[x]

Table 4-8 presents the nationwide emission reduction estimates for each regulatory option. It was estimated that RECs in combination with the combustion of gas unsuitable for entering the gathering line, can achieve an overall 95 percent VOC reduction over the duration of the completion operation. The 95 percent recovery was estimated based on 90 percent of flowback being captured to the sales line and assuming an additional 5 percent of the remaining flowback would be sent to the combustion device. Nationwide emission reductions were estimated by applying this 95 percent VOC reduction to the uncontrolled baseline emissions presented in Table 4-4.

4.5.2.2 Cost Impacts

Cost impacts of the individual control techniques (RECs and completion combustion devices) were presented in section 4.4. For Regulatory Option 6, the costs for completion combustion devices presented in Table 4-6 for would apply to Subcategory 2 completions. The cost per completion event was estimated to be $3,523. Applied to the 446 estimated Subcategory 2 completions, the nationwide costs were estimated to be $1.57 million. Completion combustion devices are assumed to achieve an overall 95 percent combustion efficiency. Since the operational standards for Regulatory Options 5 and 7 include both REC and completion combustion devices, an additional cost impact analysis was

[x] The number of uncontrolled recompletions at new wells is not included in this analysis. Based on the assumption that wells are recompleted once every 10 years, any new wells that are drilled after the date of proposal of the standard would not likely be recompleted until after the year 2015, which is the date of this analysis. Therefore, impacts were not estimated for recompletion of new wells, which will be subject to the standards.

Table 4-8. Nationwide Emission and Cost Analysis of Regulatory Option

Well Completion Category	Number of Sources subject to NSPS[a]	Annual Cost Per Completion Event ($)[b]	Nationwide Emission Reductions (tpy)[c]			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
			VOC	Methane	HAP	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 5 (operational standard for REC and combustion)												
Subcategory 1: Natural gas Completions with Hydraulic Fracturing	9,313	33,237	204,134	1,399,139	14,831	1,516	net savings	221	net savings	309.5	309.5	(20.24)
Regulatory Option 6 (operational standard for combustion)												
Subcategory 2: Natural gas Completions with Hydraulic Fracturing	446	3,523	9,801	67,178	712	160	160	23	23	1.57	1.57	1.57
Regulatory Option 7 (operational standard for REC and combustion)												
Natural Gas Well Recompletions with Hydraulic Fracturing	12,050	33,237	264,115	1,810,245	19,189	1,516	net savings	221	net savings	400.5	400.5	(26.18)

Minor discrepancies may be due to rounding.

a. Number of sources in each well completion category that are uncontrolled at baseline as presented in Table 4-3.
b. Costs per event for Regulatory Options 5 and 7 are calculated by adding the costs for REC and completion combustion device presented in Tables 4-5 and 4-6, respectively. Cost per event for Regulatory Option 6 is presented for completion combustion devices in Table 4-6.
c. Nationwide emission reductions calculated by applying the 95 percent emission reduction efficiency to the uncontrolled nationwide baseline emissions in Table 4-4.

performed to analyze the nationwide cost impacts of these regulatory options. The total incremental cost of the operational standard for Subcategory 1 completions and for recompletions is estimated at around $33,237, which includes the costs in Table 4-5 for the REC equipment and transportation in addition to the costs in Table 4-6 for the completion combustion device. Applying the cost for the combined REC and completion combustion device to the estimated 9,313 Subcategory 1 completions, the total nationwide cost was estimated to be $309.5 million, with a net annual savings estimated around $20 million when natural gas savings are considered. A cost of $400.5 million was estimated for recompletions, with an overall savings of around $26 million when natural gas savings are considered. The VOC cost effectiveness for Regulatory Options 5 and 7 was estimated at around $1,516 per ton, with a methane co-benefit of $221 per ton.

4.5.2.3 Secondary Impacts

Regulatory Options 5, 6 and 7 all require some amount of combustion; therefore the estimated nationwide secondary impacts are a direct result of combusting all or partial flowback emissions. Although, it is understood the volume of gas captured, combusted and vented may vary significantly depending on well characteristics and flowback composition, for the purpose of estimating secondary impacts for Regulatory Options 5 and 7, it was assumed that ninety percent of flowback is captured and an additional five percent of the remaining gas is combusted. For both Subcategory 1 natural gas well completions with hydraulic fracturing and for natural gas well recompletions with hydraulic fracturing, it is assumed around 459 Mcf of natural gas is combusted on a per well basis. For Regulatory Option 6, Subcategory 2 natural gas completions with hydraulic fracturing, it is assumed that 95 percent (8,716 Mcf) of flowback emissions are consumed by the combustion device. Tons of pollutant per completion event was estimated assuming 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas and applying the AP-42 emissions factors listed in Table 4-7.

From category 1 well completions and from recompletions, it is estimated 0.02 tons of NO_x are produced per event. This is based on assumptions that 5 percent of the flowback gas is combusted by the combustion device. From category 2 well completions, it is estimated 0.32 tons of NO_x are produced in secondary emissions per event. This is based on the assumption 95 percent of flowback gas is combusted by the combustion device. Based on the estimated number of completions and recompletions, the proposed regulatory options are estimated to produce around 507 tons of NO_x in secondary emissions nationwide from controlling all or partial flowback by combustion. Table 4-9 summarizes the estimated secondary emissions of the selected regulatory options.

Table 4-9 Nationwide Secondary Impacts of Selected Regulatory Options[a]

Pollutant	Regulatory Options 5[b] Subcategory 1 Natural Gas Well Completions with Hydraulic Fracturing		Regulatory Option 6[c] Subcategory 2 Natural Gas Well Completions with Hydraulic Fracturing		Regulatory Options 7[b] Natural Gas Well Recompletions with Hydraulic Fracturing	
	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)	tons per event[d]	Nationwide Annual Secondary Emissions (tons/year)
Total Hydrocarbons	0.03	326	0.66	296	0.03	422
Carbon Monoxide	0.09	861	1.76	783	0.09	1,114
Nitrogen Oxides	0.02	158	0.32	144	0.02	205
Particulate Matter	0.00000002	0.0002	0.011	5	0.00000002	0.0003
Carbon Dioxide	33.06	307,863	628	280,128	33.06	398,341

a. Nationwide impacts are based on AP-42 Emission Guidelines for Industrial Flares as outlined in Table 4-7. As such, these emissions should be considered the minimum level of secondary emissions expected.

b. The operational standard (Regulatory Options 5 and 7) combines REC and combustion is assumed to capture 90 percent of flowback gas. Five percent of the remaining flowback is assumed to be consumed in the combustion device. Therefore, it is estimated 459 Mcf is sent to the combustion device per completion event. This analysis assumes there are 9,313 Subcategory 1 wells and 12,050 recompletions.

c. Assumes 8,716 Mcf of natural gas is sent to the combustion unit per completion. This analysis assumes 446 exploratory wells fall into this category.

d. Based on 1,089.3 Btu/scf saturated gross heating value of the "raw" natural gas.

4.6 References

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5.0 PNEUMATIC CONTROLLERS

The natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature, and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic; (2) electrical; or (3) mechanical. Of these, only pneumatic devices are direct sources of air emissions. Pneumatic controllers are used throughout the oil and natural gas sector as part of the instrumentation to control the position of valves. This chapter describes pneumatic devices including their function and associated emissions. Options available to reduce emissions from pneumatic devices are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for pneumatic devices.

5.1 Process Description

For the purpose of this document, a pneumatic controller is a device that uses natural gas to transmit a process signal or condition pneumatically and that may also adjust a valve position based on that signal, with the same bleed gas and/or a supplemental supply of power gas. In the vast majority of applications, the natural gas industry uses pneumatic controllers that make use of readily available high-pressure natural gas to provide the required energy and control signals. In the production segment, an estimated 400,000 pneumatic devices control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. There are around 13,000 gas pneumatic controllers located in the gathering, boosting and processing segment that control and monitor temperature, liquid, and pressure levels. In the transmission segment, an estimated 85,000 pneumatic controllers actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities.[1]

Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations across all segments of the oil and gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate control of a valve. In these “gas-driven” pneumatic controllers, natural gas may be released with every valve movement and/or continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady-state rates when operated under similar conditions. There are three basic designs: (1) continuous bleed devices are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time; (2) snap-acting devices release gas only when they open or close a valve or as they throttle the gas flow; and (3) self-contained devices release gas to a downstream pipeline instead of to the atmosphere. This analysis assumes self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. Furthermore, it is recognized “closed loop” systems are applicable only in instances with very low pressure[2] and may not be suitable to replace many applications of bleeding pneumatic devices. Therefore, these devices are not further discussed in this analysis.

Snap-acting controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. The actual amount of emissions from snap-acting devices is dependent on the amount of natural gas vented per actuation and how often it is actuated. Bleed devices also vent an additional volume of gas during actuation, in addition to the device’s bleed stream. Since actuation emissions serve the device’s functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in section 5.2.2) account for only the continuous flow of emissions (i.e. the bleed rate) and do not include emissions directly resulting from actuation. Snap-acting controllers are assumed to have zero bleed emissions. Most applications (but not all), snap-acting devices serve functionally different purposes than bleed devices. Therefore, snap-acting controllers are not further discussed in this analysis.

In addition, not all pneumatic controllers are gas driven. At sites without electrical service sufficient to power an instrument air compressor, mechanical or electrically powered pneumatic devices can be used. These “non-gas driven” pneumatic controllers can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed “instrument air.” Because these devices are not gas driven, they do not directly release natural gas or VOC emissions. However, electrically powered systems have energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. Instrument air systems are feasible only at oil and natural gas locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient to power an air compressor. This analysis assumes that natural gas processing plants are the only facilities in the oil and natural gas sector highly likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of gas driven devices.[9] The application of electrical controls is further elaborated in Section 5.3.

5.2 Emissions Data and Information

5.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic devices and the potential options available to reduce these emissions, numerous studies were consulted. Table 5-1 lists these references with an indication of the type of relevant information contained in each study.

5.2.2 Representative Pneumatic Device Emissions

Bleeding pneumatic controllers can be classified into two types based on their emissions rates: (1) high-bleed controllers and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 standard cubic feet per hour (scfh), while low-bleed devices bleed at a rate less than or equal to 6 scfh.[i]

For this analysis, EPA consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices, Subpart W of the Greenhouse Gas Reporting rule, as well as obtained updated data from major vendors of pneumatic devices. The data obtained from vendors included emission rates, costs, and any other pertinent information for each pneumatic device model (or model family). All pneumatic devices that a vendor offered were itemized and inquiries were made into the specifications of each device and whether it was applicable to oil and natural gas operations. High-bleed and low-bleed devices were differentiated using the 6 scfh threshold.

Although by definition, a low-bleed device can emit up to 6 scfh, through this vendor research, it was determined that the typical low-bleed device available currently on the market emits lower than the maximum rate allocated for the device type. Specifically, low-bleed devices on the market today have emissions from 0.2 scfh up to 5 scfh. Similarly, the available bleed rates for a high bleed device vary significantly from venting as low as 7 scfh to as high as 100 scfh.[3,ii] While the vendor data provides useful information on specific makes and models, it did not yield sufficient information about the

[i] The classification of high-bleed and low-bleed devices originated from a report by Pacific Gas & Electric (PG&E) and the Gas Research Institute (GRI) in 1990 titled "Unaccounted for Gas Project Summary Volume." This classification was adopted for the October 1993 Report to Congress titled "Opportunities to Reduce Anthropogenic Methane Emissions in the United States". As described on page 2-16 of the report, "devices with emissions or 'bleed' rates of 0.1 to 0.5 cubic feet per minute are considered to be 'high-bleed' types (PG&E 1990)." This range of bleed rates is equivalent to 6 to 30 cubic feet per hour.

[ii] All rates are listed at an assumed supply gas pressure of 20 psig.

Table 5-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Number of Devices	Emissions Information	Control Information
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Document [3]	EPA	2010	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2009 [4, 5]	EPA	2011	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry [6, 7, 8, 9]	Gas Research Institute / EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry (draft) [10]	EPA	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry [11]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [12]	Western Regional Air Partnership	2005	Regional	X	
Natural Gas STAR Program[1]	EPA	2000-2010		X	X

prevalence of each model type in the population of devices; which is an important factor in developing a representative emission factor. Therefore, for this analysis, EPA determined that best available emissions estimates for pneumatic devices are presented in Table W-1A and W-1B of the Greenhouse Gas Mandatory Reporting Rule for the Oil and Natural Gas Industry (Subpart W). However, for the natural gas processing segment, a more conservative approach was assumed since it has been determined that natural gas processing plants would have sufficient electrical service to upgrade to non-gas driven controls. Therefore, to quantify representative emissions from a bleed-device in the natural gas processing segment, information from Volume 12 of the EPA/GRI report[iii] was used to estimate the methane emissions from a single pneumatic device by type.

The basic approach used for this analysis was to first approximate methane emissions from the average pneumatic device type in each industry segment and then estimate VOC and hazardous air pollutants (HAP) using a representative gas composition.[13] The specific ratios from the gas composition were 0.278 pounds VOC per pound methane and 0.0105 pounds HAP per pound methane in the production and processing segments, and 0.0277 pounds VOC per pound methane and 0.0008 pounds HAP per pound methane in the transmission segment. Table 5-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment and device type.

5.3 Nationwide Emissions from New Sources

5.3.1 Approach

Nationwide emissions from newly installed natural gas pneumatic devices for a typical year were calculated by estimating the number of pneumatic devices installed in a typical year and multiplying by the estimated annual emissions per device listed in Table 5-2. The number of new pneumatic devices installed for a typical year was determined for each segment of the industry including natural gas production, natural gas processing, natural gas transmission and storage, and oil production. The methodologies that determined the estimated number of new devices installed in a typical year is provided in section 5.3.2 of this chapter.

5.3.2 Population of Devices Installed Annually

In order to estimate the average number of pneumatic devices installed in a typical year, each industry

[iii] Table 4-11. page 56. epa.gov/gasstar/tools/related.html

Table 5-2. Average Bleed Emission Estimates per Pneumatic Device in the Oil and Natural Gas Sector (tons/year)[a]

Industry Segment	High-Bleed			Low-Bleed		
	Methane	VOC	HAP	Methane	VOC	HAP
Natural Gas Production[b]	6.91	1.92	0.073	0.26	0.072	0.003
Natural Gas Transmission and Storage[c]	3.20	0.089	0.003	0.24	0.007	0.0002
Oil Production[d]	6.91	1.92	0.073	0.26	0.072	0.003
Natural Gas Processing[e]	1.00	0.28	0.01	1.00	0.28	0.01

Minor discrepancies may be due to rounding.

a. The conversion factor used in this analysis is 1 thousand cubic feet of methane (Mcf) is equal to 0.0208 tons methane. Minor discrepancies may be due to rounding.
b. Natural Gas Production methane emissions are derived from Table W-1A and W-1B of Subpart W.
c. Natural gas transmission and storage methane emissions are derived from Table W-3 of Subpart W.
d. Oil production methane emissions are derived from Table W-1A and W-1B of Subpart W. It is assumed only continuous bleed devices are used in oil production.
e. Natural gas processing sector methane emissions are derived from Volume 12 of the 1996 GRI report.[9] Emissions from devices in the processing sector were determined based on data available for snap-acting and bleed devices, further distinction between high and low bleed could not be determined based on available data.

segment was analyzed separately using the best data available for each segment. The number of facilities estimated in absence of regulation was undeterminable due to the magnitude of new sources estimated and the lack of sufficient data that could indicate the number of controllers that would be installed in states that may have regulations requiring low bleed controllers, such as in Wyoming and Colorado.

For the natural gas production and oil production segments, the number of new pneumatics installed in a typical year was derived using a multiphase analysis. First, data from the US Greenhouse Gas Inventory: Emission and Sinks 1990-2009 was used to establish the ratio of pneumatic controllers installed per well site on a regional basis. These ratios were then applied to the number of well completions estimated in Chapter 4 for natural gas well completions with hydraulic fracturing, natural gas well completions without hydraulic fracturing and for oil well completions. On average, one pneumatic device was assumed to be installed per well completion for a total of 33,411 pneumatic devices. By applying the estimated 51 percent of bleed devices (versus snap acting controllers), it is estimated that an average of 17,040 bleed-devices would be installed in the production segment in a typical year.

The number of pneumatic controllers installed in the transmission segment was approximated using the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009. The number of new devices installed in a given year was estimated by subtracting the prior year (e.g. 2007) from the given year's total (e.g. 2008). This difference was assumed to be the number of new devices installed in the latter year (e.g. Number of new devices installed during 2008 = Pneumatics in 2008 – Pneumatics in 2007). A 3-year average was calculated based on the number of new devices installed in 2006 through 2008 in order to determine the average number of new devices installed in a typical year.

Once the population counts for the number of pneumatics in each segment were established, this population count was further refined to account for the number of snap-acting devices that would be installed versus a bleed device. This estimate of the percent of snap-acting and bleed devices was based on raw data found in the GRI study, where 51 percent of the pneumatic controllers are bleed devices in the production segment, and 32 percent of the pneumatic controllers are bleed devices in the transmission segment.9 The distinction between the number of high-bleed and low-bleed devices was not estimated because this analysis assumes it is not possible to predict or ensure where low bleeds will be used in the future. Table 5-3 summarizes the estimated number of new devices installed per year.

Table 5-3. Estimated Number of Pneumatic Devices Installed in an Typical Year

Industry Segment	Number of New Devices Estimated for a Typical Year[a]		
	Snap-Acting	Bleed-Devices	Total
Natural Gas and Oil Production[b]	16,371	17,040	33,411
Natural Gas Transmission and Storage[c]	178	84	262

a. National averages of population counts from the Inventory were refined to include the difference in snap-acting and bleed devices based on raw data found in the GRI/EPA study. This is based on the assumption that 51 percent of the pneumatic controllers are bleed devices in the production segment, while 32 percent are bleed devices in the transmission segment.

b. The number of pneumatics was derived from a multiphase analysis. Data from the US Greenhouse Gas Inventory: Emission and Sinks 1990-2009 was used to establish the number of pneumatics per well on a regional basis. These ratios were applied to the number of well completions estimated in Chapter 4 for natural gas wells with hydraulic fracturing, natural gas wells without hydraulic fracturing and for oil wells.

c. The number of pneumatics estimated for the transmission segment was approximated from comparing a 3 year average of new devices installed in 2006 through 2008 in order to establish an average number of pneumatics being installed in this industry segment in a typical year. This analysis was performed using the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009.

For the natural gas processing segment, this analysis assumes that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e. an instrument air system) and any high-bleed devices that remain are safety related. As a result, the number of new pneumatic bleed devices installed at existing natural gas processing plants was estimated as negligible. A new greenfield natural gas processing plant would require multiple control loops. In Chapter 8 of this document, it is estimated that 29 new and existing processing facilities would be subject to the NSPS for equipment leak detection. In order to quantify the impacts of the regulatory options represented in section 5.5 of this Chapter, it is assumed that half of these facilities are new sites that will install an instrument air system in place of multiple control valves. This indicates about 15 instrument air systems will be installed in a representative year.

5.3.3 Emission Estimates

Nationwide baseline emission estimates for pneumatic devices for new sources in a typical year are summarized in Table 5-4 by industry segment and device type. This analysis assumed for the nationwide emission estimate that all bleed-devices have the high-bleed emission rates estimated in Table 5-2 per industry segment since it cannot be predicted which sources would install a low bleed versus a high bleed controller.

5.4 Control Techniques

Although pneumatic devices have relatively small emissions individually, due to the large population of these devices installed on an annual basis, the cumulative VOC emissions for the industry are significant. As a result, several options to reduce emissions have been developed over the years. Table 5-5 provides a summary of these options for reducing emissions from pneumatic devices including: instrument air, non-gas driven controls, and enhanced maintenance.

Given the various control options and applicability issues, the replacement of a high-bleed with a low-bleed device is the most likely scenario for reducing emissions from pneumatic device emissions. This is also supported by States such as Colorado and Wyoming that require the use of low-bleed controllers in place of high-bleed controllers. Therefore, low-bleed devices are further described in the following section, along with estimates of the impacts of their application for a representative device and nationwide basis. Although snap-acting devices have zero bleed emissions, this analysis assumes the

Table 5-4. Nationwide Baseline Emissions from Representative Pneumatic Device Installed in a Typical Year for the Oil and Natural Gas Industry (tons/year)[a]

Industry Segment	Baseline Emissions from Representative New Unit (tpy)			Number of New Bleed Devices Expected Per Year	Nationwide Baseline Emissions from Bleeding Pneumatic (tpy)[b]		
	VOC	Methane	HAP		VOC	Methane	HAP
Oil and Gas Production	1.9213	6.9112	0.0725	17,040	32,739	117,766	1,237
Natural Gas Transmission and Storage	0.09523	3.423	0.003	84	8	288	0.2

Minor discrepancies may be due to rounding.

a. Emissions have been based on the bleed rates for a high-bleed device by industry segment. Minor discrepancies may be due to rounding.
b. To estimate VOC and HAP, weight ratios were developed based on methane emissions per device. The specific ratios used were 0.278 pounds VOC per pound methane and 0.0105 pounds HAP per pound methane in the production and processing segments, and 0.0277 pounds VOC per pound methane and 0.0008 pounds HAP per pound methane in the transmission segment.

Table 5-5. Alternative Control Options for Pneumatic Devices

Option	Description	Applicability/Effectiveness	Estimated Cost Range
Install Low Bleed Device in Place of High Bleed Device	Low-bleed devices provide the same functional control as a high-bleed device, while emitting less continuous bleed emissions.	Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller.	Low-bleed devices are, on average, around $165 more than high bleed versions.
Convert to Instrument Air[14]	Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. In this type of system, atmospheric air is compressed, stored in a tank, filtered and then dried for instrument use. For utility purposes such as small pneumatic pumps, gas compressor motor starters, pneumatic tools and sand blasting, air would not need to be dried. Instrument air conversion requires additional equipment to properly compress and control the pressured air. This equipment includes a compressor, power source, air dehydrator and air storage vessel.	Replacing natural gas with instrument air in pneumatic controls eliminates VOC emissions from bleeding pneumatics. It is most effective at facilities where there are a high concentration of pneumatic control valves and an operator present. Since the systems are powered by electric compressors, they require a constant source of electrical power or a back-up natural gas pneumatic device. These systems can achieve 100 percent reduction in emissions.	A complete cost analysis is provided in Section 5.4.2. System costs are dependent on size of compressor, power supply needs, labor and other equipment.
Mechanical and Solar Powered Systems in place of Bleed device[15]	Mechanical controls operate using a simple design comprised of levers, hand wheels, springs and flow channels. The most common mechanical control device is the liquid-level float to the drain valve position with mechanical linkages. Electricity or small electrical motors (including solar powered) have been used to operate valves. Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of back-up power or storage to ensure reliability.	Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations. Electric powered valves are only reliable with a constant supply of electricity. Overall, these options are applicable in niche areas but can achieve 100 percent reduction in emissions where applicable.	Depending on supply of power, costs can range from below $1,000 to $10,000 for entire systems.
Enhanced Maintenance[16]	Instrumentation in poor condition typically bleeds 5 to 10 scf per hour more than representative conditions due to worn seals, gaskets, diaphragms; nozzle corrosion or wear, or loose control tube fittings. This may not impact the operations but does increase emissions.	Enhanced maintenance to repair and maintain pneumatic devices periodically can reduce emissions. Proper methods of maintaining a device are highly variable and could incur significant costs.	Variable based on labor, time, and fuel required to travel to many remote locations.

devices are not always used in the same functional application as bleed devices and are, therefore, not an appropriate form of control for all bleed devices. It is assumed snap-acting, or no-bleed, devices meet the definition of a low-bleed. This concept is further detailed in Section 5.5 of this chapter. Since this analysis has assumed areas with electrical power have already converted applicable pneumatic devices to instrument air systems, instrument air systems are also described for natural gas processing plants only. Given applicability, efficiency and the expected costs of the other options identified in Table 5-5 (i.e. mechanical controls and enhanced maintenance), were not further conducted for this analysis.

5.4.1 Low-Bleed Controllers

5.4.1.1 Emission Reduction Potential

As discussed in the above sections, low-bleed devices provide the same functional control as a high-bleed device, but have lower continuous bleed emissions. As summarized in Table 5-6, it is estimated on average that 6.6 tons of methane and 1.8 tons of VOC will be reduced annually in the production segment from installing a low-bleed device in place of a high-bleed device. In the transmission segment, the average achievable reductions per device are estimated around 3.7 tons and 0.08 tons for methane and VOC, respectively. As noted in section 5.2, a low-bleed controller can emit up to 6 scfh, which is higher than the expected emissions from the typical low-bleed device available on the current market.

5.4.1.1 Effectiveness

There are certain situations in which replacing and retrofitting are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high bleed rate to actuate, or a safety isolation valve is involved. Based on criteria provided by the Natural Gas STAR Program, it is assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices throughout the production and transmission and storage industry segments.[1] This corresponds to 13,632 new high-bleed devices in the production segment (out of 17,040) and 67 new high-bleed devices in the transmission and storage segment (out of 84) that can be replaced with a new low-bleed alternative. For high-bleed devices in natural gas processing, this analysis assumed that the replaceable devices have already been replaced with instrument air and the remaining high-bleed devices are safety related for about half of the existing processing plants.

Table 5-6. Estimated Annual Bleed Emission Reductions from Replacing a Representative High-Bleed Pneumatic Device with a Representative Low-Bleed Pneumatic Device

Segment/Device Type	Emissions (tons/year)[a]		
	Methane	VOC	HAP
Oil and Natural Gas Production	6.65	1.85	0.07
Natural Gas Transmission and Storage	2.96	0.082	0.002

Minor discrepancies may be due to rounding.

a. Average emission reductions for each industry segment based on the typical emission flow rates from high-bleed and low-bleed devices as listed in Table 5-2 by industry segment.

Applicability may depend on the function of instrumentation for an individual device on whether the device is a level, pressure, or temperature controller. High-bleed pneumatic devices may not be applicable for replacement with low-bleed devices because a process condition may require a fast or precise control response so that it does not stray too far from the desired set point. A slower-acting controller could potentially result in damage to equipment and/or become a safety issue. An example of this is on a compressor where pneumatic devices may monitor the suction and discharge pressure and actuate a re-cycle when one or the other is out of the specified target range. Other scenarios for fast and precise control include transient (non-steady) situations where a gas flow rate may fluctuate widely or unpredictably. This situation requires a responsive high-bleed device to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes can accommodate control from a low-bleed device, which is slower-acting and less precise.

Safety concerns may be a limitation issue, but only in specific situations because emergency valves are not bleeding controllers since safety is the pre-eminent consideration. Thus, the connection between the bleed rate of a pneumatic device and safety is not a direct one. Pneumatic devices are designed for process control during normal operations and to keep the process in a normal operating state. If an Emergency Shut Down (ESD) or Pressure Relief Valve (PRV) actuation occurs,[iv] the equipment in place for such an event is spring loaded, or otherwise not pneumatically powered. During a safety issue or emergency, it is possible that the pneumatic gas supply will be lost. For this reason, control valves are deliberately selected to either fail open or fail closed, depending on which option is the failsafe.

5.4.1.2 Cost Impacts

As described in Section 5.2.2, costs were based on the vendor research described in Section 5.2 as a result of updating and expanding upon the information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices.[1] As Table 5-7 indicates, the average cost for a low bleed pneumatic is $2,553, while the average cost for a high bleed is $2,338.[v] Thus, the incremental cost of installing a low-bleed device instead of a high-bleed device is on the order of $165 per device. In order to analyze cost impacts, the incremental cost to install a low-bleed instead of a high-bleed was

[iv] ESD valves either close or open in an emergency depending on the fail safe configuration. PRVs always open in an emergency.
[v] Costs are estimated in 2008 U.S. Dollars.

Table 5-7. Cost Projections for the Representative Pneumatic Devices[a]

Device	Minimum cost ($)	Maximum cost ($)	Average cost ($)	Low-Bleed Incremental Cost ($)
High-bleed controller	366	7,000	2,388	$165
Low-bleed controller	524	8,852	2,553	

a. Major pneumatic devices vendors were surveyed for costs, emission rates, and any other pertinent information that would give an accurate picture of the present industry.

annualized for a 10 year period using a 7 percent interest rate. This equated to an annualized cost of around $23 per device for both the production and transmission segments.

Monetary savings associated with additional gas captured to the sales line was estimated based on a natural gas value of $4.00 per Mcf.[vi,17] The representative low-bleed device is estimated to emit 6.65 tons, or 319 Mcf, (using the conversion factor of 0.0208 tons methane per 1 Mcf) of methane less than the average high-bleed device per year. Assuming production quality gas is 82.8 percent methane by volume, this equals 385.5 Mcf natural gas recovered per year. Therefore, the value of recovered natural gas from one pneumatic device in the production segment equates to approximately $1,500. Savings were not estimated for the transmission segment because it is assumed the owner of the pneumatic controller generally is not the owner of the natural gas. Table 5-8 provides a summary of low-bleed pneumatic cost effectiveness.

5.4.1.3 Secondary Impacts

Low-bleed pneumatic devices are a replacement option for high-bleed devices that simply bleed less natural gas that would otherwise be emitted in the actuation of pneumatic valves. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the use of low-bleed pneumatic devices.

5.4.2 Instrument Air Systems

5.4.2.1 Process Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator, and volume tank. The following is a description of each component as described in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air:*

- Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank.

[vi] The average market price for natural gas in 2010 was approximately $4.16 per Mcf. This is much less compared to the average price in 2008 of $7.96 per Mcf. Due to the volatility in the value, a conservative savings of $4.00 per Mcf estimate was projected for the analysis in order to not overstate savings.

Table 5-8. Cost-effectiveness for Low-Bleed Pneumatic Devices versus High Bleed Pneumatics

Segment	Incremental Capital Cost Per Unit ($)[a]	Total Annual Cost Per Unit ($/yr)[b]		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		without savings	with savings	without savings	with savings	without savings	with savings
Oil and Natural Gas Production	165	23.50	-1,519	13	net savings	4	net savings
Natural Gas Transmission and Storage	165	23.50	23.50	286	286	8	8

a. Incremental cost of a low bleed device versus a high bleed device as summarized in Table 5-7.
b. Annualized cost assumes a 7 percent interest rate over a 10 year equipment lifetime.

For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.

- A critical component of the instrument air control system is the power source required to operate the compressor. Since high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and in remote locations, however, a reliable source of electric power can be difficult to assure. In some instances, solar-powered battery-operated air compressors can be cost effective for remote locations, which reduce both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.

- Dehydrators, or air dryers, are also an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.

- The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. The use of instrument air eliminates natural gas emissions from natural gas powered pneumatic controllers. All other parts of a gas pneumatic system will operate the same way with instrument air as they do with natural gas. The conversion of natural gas pneumatic controllers to instrument air systems is applicable to all natural gas facilities with electrical service available.[14]

5.4.2.2 Effectiveness

The use of instrument air eliminates natural gas emissions from the natural gas driven pneumatic devices; however, the system is only applicable in locations with access to a sufficient and consistent supply of electrical power. Instrument air systems are also usually installed at facilities where there is a high concentration of pneumatic control valves and the presence of an operator that can ensure the system is properly functioning.[14]

5.4.2.3 Cost Impacts

Instrument air conversion requires additional equipment to properly compress and control the pressured air. The size of the compressor will depend on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas used to run the existing instrumentation – adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is one cubic foot per minute (cfm) of instrument air for each control loop.[14] As the system is powered by electric compressors, the system requires a constant source of electrical power or a back-up pneumatic device. Table 5-9 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and related equipment and the operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator and a storage vessel. It is assumed that in either an instrument air solution or a natural gas pneumatic solution, gas supply piping, control instruments, and valve actuators of the gas pneumatic system are required. The total cost, including installation and labor, of three representative sizes of compressors were evaluated based on assumptions found in the Natural Gas STAR document, "Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air"[14] and summarized in Table 5-10.[vii]

For natural gas processing, the cost-effectiveness of the three representative instrument air system sizes was evaluated based on the emissions mitigated from the number of control loops the system can provide and not on a per device basis. This approach was chosen because we assume new processing plants will need to provide instrumentation of multiple control loops and size the instrument air system accordingly. We also assume that existing processing plants have already upgraded to instrument air

[vii] Costs have been converted to 2008 US dollars using the Chemical Engineering Cost Index.

Table 5-9. Compressor Power Requirements and Costs for Various Sized Instrument Air Systems[a]

Compressor Power Requirements[b]			Flow Rate	Control Loops
Size of Unit	hp	kW	(cfm)	Loops/Compressor
small	10	13.3	30	15
medium	30	40	125	63
large	75	100	350	175

a. Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*[14]

b. Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50 percent of the year).

Table 5-10 Estimated Capital and Annual Costs of Various Sized Representative Instrument Air Systems

Instrument Air System Size	Compressor	Tank	Air Dryer	Total Capital[a]	Annualized Capital[b]	Labor Cost	Total Annual Costs[c]	Annualized Cost of Instrument Air System
Small	$3,772	$754	$2,262	$16,972	$2,416	$1,334	$8,674	$11,090
Medium	$18,855	$2,262	$6,787	$73,531	$10,469	$4,333	$26,408	$36,877
Large	$33,183	$4,525	$15,083	$135,750	$19,328	$5,999	$61,187	$80,515

a. Total Capital includes the cost for two compressors, tank, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the Natural Gas Star Lessons Learned document and converted to 2008 dollars from 2006 dollars using the Chemical Engineering Cost Index.

b. The annualized cost was estimated using a 7 percent interest rate and 10 year equipment life.

c. Annual Costs include the cost of electrical power as listed in Table 5-9 and labor.

unless the function has a specific need for a bleeding device, which would most likely be safety related.[9] Table 5-11 summarizes the cost-effectiveness of the three sizes of representative instrument air systems.

5.4.2.4 Secondary Impacts

The secondary impacts from instrument air systems are indirect, variable and dependent on the electrical supply used to power the compressor. No other secondary impacts are expected.

5.5 Regulatory Options

The affected facility definition for pneumatic controllers is defined as a single natural gas pneumatic controller. Therefore, pneumatic controllers would be subject to a New Source Performance Standard (NSPS) at the time of installation. The following Regulatory alternatives were evaluated:

- Regulatory Option 1: Establish an emissions limit equal to 0 scfh.
- Regulatory Option 2: Establish an emissions limit equal to 6 scfh.

5.5.1 Evaluation of Regulatory Options

By establishing an emission limit of 0 scfh, facilities would most likely install instrument air systems to meet the threshold limit. This option is considered cost effective for natural gas processing plants as summarized in Table 5-11. A major assumption of this analysis, however, is that processing plants are constructed at a location with sufficient electrical service to power the instrument air compression system. It is assumed that facilities located outside of the processing plant would not have sufficient electrical service to install an instrument air system. This would significantly increase the cost of the system at these locations, making it not cost effective for these facilities to meet this regulatory option. Therefore, Regulatory Option 1 was accepted for natural gas processing plants and rejected for all other types of facilities.

Regulatory Option 2 would establish an emission limit equal to the maximum emissions allowed for a low-bleed device in the production and transmissions and storage industry segments. This would most likely be met by the use of low-bleed controllers in place of a high-bleed controller, but allows flexibility in the chosen method of meeting the requirement. In the key instances related to pressure control that would disallow the use of a low-bleed device, specific monitoring and recordkeeping criteria

Table 5-11 Cost-effectiveness of Representative Instrument Air Systems in the Natural Gas Processing Segment

System Size	Number of Control Loops	Annual Emissions Reduction[a] (tons/year)			Value of Product Recovered ($/year)[b]	Annualized Cost of System		VOC Cost-effectiveness ($/ton)		Methane Cost-effectiveness ($/ton)	
		VOC	CH_4	HAP		without savings	with savings	without savings	with savings	without savings	with savings
Small	15	4.18	15	0.16	3,484	11,090	7,606	2,656	1,822	738	506
Medium	63	17.5	63	0.66	14,632	36,877	22,245	2,103	1,269	585	353
Large	175	48.7	175	1.84	40,644	80,515	39,871	1,653	819	460	228

Minor discrepancies may be due to rounding.

a. Based on the emissions mitigated from the entire system, which includes multiple control loops.
b. Value of recovered product assumes natural gas processing is 82.8 percent methane by volume. A natural gas price of $4 per Mcf was assumed.

would be required to ensure the device function dictates the precision of a high bleed device. Therefore, Regulatory Option 2 was accepted for locations outside of natural gas processing plants.

5.5.2 Nationwide Impacts of Regulatory Options

Table 5-12 summarizes the costs impacts of the selected regulatory options by industry segment. Regulatory Option 1 for the natural gas processing segment is estimated to affect 15 new processing plants with nationwide annual costs discounting savings of $166,000. When savings are realized the net annual cost is reduced to around $114,000. Regulatory Option 2 has nationwide annual costs of $320,000 for the production segment and around $1,500 in the natural gas transmission and storage segment. When annual savings are realized in the production segment there is a net savings of $20.7 million in nationwide annual costs.

Table 5-12 Nationwide Cost and Emission Reduction Impacts for Selected Regulatory Options by Industry Segment

Industry Segment	Number of Sources subject to NSPS*	Capital Cost Per Device/IAS ($)**	Annual Costs ($/year)		Nationwide Emission Reductions (tpy)†			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs ($/year)		
			without savings	with savings	VOC	Methane	HAP	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 1 (emission threshold equal to 0 scfh)														
Natural Gas Processing	15	16,972	11,090	7,606	63	225	2	2,656	1,822	738	506	254,576	166,351	114,094
Regulatory Option 2 (emission threshold equal to 6 scfh)														
Oil and Natural Gas Production	13,632	165	23	(1,519)	25,210	90,685	952	13	net savings	4	net savings	2,249,221	320,071	(20,699,918)
Natural Gas Transmission and Storage	67	165	23	23	6	212	0.2	262	262	7	7	11,039	1,539	1,539

Minor discrepancies may be due to rounding.

a. The number of sources subject to NSPS for the natural gas processing and the natural gas transmission and storage segments represent the number of new devices expected per year reduced by 20 percent. This is consistent with the assumption that 80 percent of high bleed devices can be replaced with a low bleed device. It is assumed all new sources would be installed as a high bleed for these segments. For the natural gas processing segment the number of new sources represents the number of Instrument Air Systems (IAS) that is expected to be installed, with each IAS expected to power 15 control loops (or replace 15 pneumatic devices).

b. The capital cost for regulatory option 2 is equal to the incremental cost of a low bleed device versus a new high bleed device. The capital cost of the IAS is based on the small IAS as summarized in Table 5-10.

c. Nationwide emission reductions vary based on average expected emission rates of bleed devices typically used in each segment industry segment as summarized in Tables 5-2.

5.6 References

1 U.S. Environmental Protection Agency. Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry. Office of Air and Radiation: Natural Gas Star. Washington, DC. February 2004

2 Memorandum to Bruce Moore from Denise Grubert. Meeting Minutes from EPA Meeting with the American Petroleum Institute. October 2011

3 U.S. Environmental Protection Agency. Greenhouse Gas Emissions Reporting From the Petroleum and Natural Gas Industry: Background Technical Support Document. Climate Change Division. Washington, DC. November 2010.

4 U.S Environmental Protection Agency. Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2008. Washington, DC.

5 U.S Environmental Protection Agency. Methodology for Estimating CH4 and CO2 Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2008. Washington, DC.

6 Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080b. June 1996.

7 Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080c. June 1996.

8 Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080e. June 1996.

9 Radian International LLC. Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices. Prepared for the Gas Research Institute and Environmental Protection Agency. EPA-600/R-96-080k. June 1996.

10 Radian International LLC, Methane Emissions from the U.S. Petroleum Industry, draft report for the U.S. Environmental Protection Agency, June 14, 1996.

11 ICF Consulting. Estimates of Methane Emissions from the U.S. Oil Industry. Prepared for the U.S. Environmental Protection Agency. 1999.

12 ENVIRON International Corporation. Oil and Gas Emission Inventories for the Western States. Prepared for Western Governors' Association. December 27, 2005.

13 Memorandum to Bruce Moore from Heather Brown. Gas Composition Methodology. July 2011

14 U.S. Environmental Protection Agency. Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air. Office of Air and Radiation: Natural Gas Star. Washington, DC. February 2004

15 U.S. Environmental Protection Agency. Pro Fact Sheet No. 301. Convert Pneumatics to Mechanical Controls. Office of Air and Radiation: Natural Gas Star. Washington, DC. September 2004.

16 CETAC WEST. Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments. Prepared for the Canadian Association of Petroleum Producers. May 2008.

17 U.S. Energy Information Administration. Annual U.S. Natural Gas Wellhead Price. Energy Information Administration. Natural Gas Navigator. Retrieved online on 12 Dec 2010 at <http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm>

6.0 COMPRESSORS

Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and gas industry as prime movers are reciprocating and centrifugal compressors. This chapter discusses the air pollutant emissions from these compressors and provides emission estimates for reducing emission from these types of compressors. In addition, nationwide emissions estimates from new sources are estimated. Options for controlling pollutant emissions from these compressors are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for both reciprocating and centrifugal compressors.

6.1 Process Description

6.1.1 Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time,during operation of the compressor, the rings become worn and the packing system will need to be replaced to prevent excessive leaking from the compression cylinder.

6.1.2 Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Many centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and absorbs some compressed natural gas which is released to the atmosphere during the seal oil recirculation process. Alternatively, dry seals can be used to replace the wet seals in centrifugal compressors. Dry seals prevent leakage by using the opposing force created by hydrodynamic groves and springs. The opposing forcescreate a thin gap of high pressure gas between the rings through which little gas can leak. The rings do not wear or need lubrication because they are not in contact with each other. Therefore, operation and maintenance costs are lower for dry seals in comparison to wet seals.

6.2 Emissions Data and Emission Factors

6.2.1 Summary of Major Studies and Emissions Factors

There are a few studies that have been conducted that provide leak estimates from reciprocating and centrifugal compressors. These studies are provided in Table 6-1, along with the type of information contained in the study.

6.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The methodology for estimating emission from reciprocating compressor rod packing was to use the methane emission factors referenced in the EPA/GRI study[1] and use the methane to pollutant ratios developed in the gas composition memorandum.[2] The emission factors in the EPA/GRI document were expressed in thousand standard cubic feet per cylinder (Mscf/cyl), and were multiplied by the average number of cylinder per reciprocating compressor at each oil and gas industry segment. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density. A summary of the methane emission factors is presented in Table 6-2. Once the methane emissions were calculated, ratios were used to estimate volatile organic compounds (VOC) and hazardous air pollutants (HAP). The specific ratios that were used for this analysis were 0.278 pounds VOC per pound of methane and 0.105 pounds HAP per pound of methane for the production and processing segments, and 0.0277 pounds VOC per pound of methane and 0.0008 pounds HAP per pound of methane for the transmission and storage segments. A summary of the reciprocating compressor emissions are presented in Table 6-3.

The compressor emission factors for wet seals and dry seals are based on data used in the GHG inventory. The wet seals methane emission factor was calculated based on a sampling of 48 wet seal centrifugal compressors. The dry seal methane emission factor was based on data collected by the

Table 6-1. Major Studies Reviewed for Consideration Of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Information	Emissions Information	Control Information
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008[1]	EPA	2010	Nationwide	X	
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Document[2]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry[3]	Gas Research Institute/EPA	1996	Nationwide	X	
Natural Gas STAR Program[4,5]	EPA	1993-2010	Nationwide	X	X

Table 6-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors

Oil and Gas Industry Segment	Reciprocating Compressors			Centrifugal Compressors	
	Methane Emission Factor (scf/hr-cylinder)	Average Number of Cylinders	Pressurized Factor (% of hour/year Compressor Pressurized)	Wet Seal Methane Emission Factor (scf/minute)	Dry Seals Methane Emission Factor (scf/minute)
Production (Well Pads)	0.271[a]	4	100%	N/A[f]	N/A[f]
Gathering & Boosting	25.9[b]	3.3	79.1%	N/A[f]	N/A[f]
Processing	57[c]	2.5	89.7%	47.7[g]	6[g]
Transmission	57[d]	3.3	79.1%	47.7[g]	6[g]
Storage	51[e]	4.5	67.5%	47.7[g]	6[g]

a. EPA/GRI. (1996). “Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks.” Table 4-8.
b. Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites.* (Draft): 2006.
c. EPA/GRI. (1996). Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks. Table 4-14.
d. EPA/GRI. (1996). “Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks.” Table 4-17.
e. EPA/GRI. (1996). “Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks.” Table 4-24.
f. The 1996 EPA/GRI Study Volume 11[3], does not report any centrifugal compressors in the production or gathering/boosting sectors, therefore no emission factor data were published for those two sectors.
g. U.S Environmental Protection Agency. Methodology for Estimating CH4 and CO2 Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks1990-2009. Washington, DC. April 2011. Annex 3. Page A-153.

Table 6-3.Baseline Emission Estimates for Reciprocating and Centrifugal Compressors

Industry Segment/ Compressor Type	Baseline Emission Estimates (tons/year)		
	Methane	**VOC**	**HAP**
Reciprocating Compressors			
Production (Well Pads)	0.198	0.0549	0.00207
Gathering & Boosting	12.3	3.42	0.129
Processing	23.3	6.48	0.244
Transmission	27.1	0.751	0.0223
Storage	28.2	0.782	0.0232
Centrifugal Compressors (Wet seals)			
Processing	228	20.5	0.736
Transmission	126	3.50	0.104
Storage	126	3.50	0.104
Centrifugal Compressors (Dry seals)			
Processing	28.6	2.58	0.0926
Transmission	15.9	0.440	0.0131
Storage	15.9	0.440	0.0131

Natural Gas STAR Program. The methane emissions were converted to VOC and HAP emissions using the same gas composition ratios that were used for reciprocating engines.[4] A summary of the emission factors are presented in Table 6-2 and the individual compressor emission are shown in Table 6-3 for each of the oil and gas industry segments.

6.3 Nationwide Emissions from New Sources

6.3.1 Overview of Approach

The number of new affected facilities in each of the oil and gas sectors was estimated using data from the U.S. Greenhouse Gas Inventory,[5,6] with some exceptions. This basis was used whenever the total number of existing facilities was explicitly estimated as part of the Inventory, so that the difference between two years can be calculated to represent the number of new facilities. The Inventory was not used to estimate the new number of reciprocating compressor facilities in gas production, since more recent information is available in the comments received to subpart W of the mandatory reporting rule. Similarly, the Inventory was not used to estimate the new number of reciprocating compressor facilities in gas gathering, since more recent information is available in comments received as comments to subpart W of the mandatory reporting rule. For both gas production and gas gathering, information received as comments to subpart W of the mandatory reporting rule was combined with additional EPA estimates and assumptions to develop the estimates for the number of new affected facilities.

Nationwide emission estimates for new sources were then determined by multiplying the number of new sources for each oil and gas segment by the expected emissions per compressor using the emission data in Table 6-3. A summary of the number of new reciprocating and centrifugal compressors for each of the oil and gas segments is presented in Table 6-4.

6.3.2 Activity Data for Reciprocating Compressors

6.3.2.1 Wellhead Reciprocating Compressors

The number of wellhead reciprocating compressors was estimated using data from industry comments on Subpart W of the Greenhouse Gas Mandatory Reporting Rule.[7] The 2010 U.S. GHG Inventory reciprocating compressor activity data was not considered in the analysis because it does not distinguish between wellhead and gathering and boosting compressors. Therefore, using data submitted to EPA during the subpart W comment period from nine basins supplied by the El Paso Corporation,[8] the

Table 6-4.Approximate Number of New Sources in the Oil and Gas Industry in 2008

<table>
<tr><th>Industry Segment</th><th>Number of New Reciprocating Compressors</th><th>Number of New Centrifugal Compressors</th></tr>
<tr><td>Wellheads</td><td>6,000</td><td>0</td></tr>
<tr><td>Gathering and Boosting</td><td>210</td><td>0</td></tr>
<tr><td>Processing</td><td>209</td><td>16</td></tr>
<tr><td>Transmission</td><td>20</td><td rowspan="2">14</td></tr>
<tr><td>Storage</td><td>4</td></tr>
</table>

average number of new wellhead compressors per new well was calculated using the 315 well head compressors provided in the El Paso comments and 3,606 wells estimated in the Final Subpart W onshore production threshold analysis. This produced an average of 0.087 compressors per wellhead. The average wellhead compressors per well was multiplied by the total well completions (oil and gas) determined from the HPDI® database[9] between 2007 and 2008, which came to 68,000 new well completions. Using this methodology, the estimated number of new reciprocating compressors at production pads was calculated to be 6,000 for 2008. A summary of the number of new reciprocating compressors located at well pads is presented in Table 6-4.

6.3.2.2 Gathering and Boosting Reciprocating Compressors

The number of gathering & boosting reciprocating compressors was also estimated using data from industry comments on Subpart W. DCP Midstream stated on page 3 of its 2010 Subpart W comments that it operates 48 natural gas processing plants and treaters and 700 gathering system compressor stations. Using this data, there were an average of 14.583 gathering and boosting compressor stations per processing plant. The number of new gathering and boosting compressors was determined by taking the average difference between the number of processing plants for each year in the 2010 U.S Inventory, which references the total processing plants in the Oil and Gas Journal. This was done for each year up to 2008. An average was taken of only the years with an increase in processing plants, up to 2008. The resulting average was multiplied by the 14.583 ratio of gathering and boosting compressor stations to processing plants and the 1.5 gathering and boosting compressors per station yielding 210 new source gathering and boosting compressor stations and is shown in Table 6-4.

6.3.2.3 Processing Reciprocating Compressors

The number of new processing reciprocating compressors at processing facilities was estimated by averaging the increase of reciprocating compressors at processing plants in the greenhouse gas inventory data for 2007, 2008, and 2009.[10,11] The estimated number of existing reciprocating compressors in the processing segment was 4,458, 4,781, and 4,876 for the years 2007, 2008, and 2009 respectively. This calculated to be 323 new reciprocating compressors between 2007 and 2008, and 95 new reciprocating compressors between 2008 and 2009. The average difference was calculated to be 209 reciprocating compressors and was used to estimate the number of new sources in Table 6-4.

6.3.2.4 Transmission and Storage Reciprocating Compressors

The number of new transmission and storage reciprocating compressors was estimated using the differences in the greenhouse gas inventory[12,13] data for 2007, 2008, and 2009 and calculating an average of those differences. The estimated number of existing reciprocating compressors at transmission stations was 7,158, 7,028, and 7,197 for the years 2007, 2008, and 2009 respectively. This calculated to be -130 new reciprocating compressors between 2007 and 2008, and 169 new reciprocating compressors between 2008and 2009. The average difference was calculated to be 20 reciprocating compressors and was used to estimate the number of new sources at transmission stations. The number of existing reciprocating compressors at storage stations was 1,144, 1,178, and 1,152 for the years 2007, 2008, and 2009 respectively. This calculated to be 34 new reciprocating compressors between 2007 and 2008, and -26 new reciprocating compressors between 2008and 2009. The average difference was calculated to be 4 reciprocating compressors and was used to estimate the number of new sources at storage stations in Table 6-4.

6.3.3 Activity Data for Centrifugal Compressors

The number of new centrifugal compressors in 2008 for the processing and transmission/storage segments was determined by taking the average difference between the centrifugal compressor activity data for each year in the 2008 U.S. Inventory . For example, the number of compressors in 1992 was subtracted from the number of compressors in 1993 to determine the number of new centrifugal compressors in 1993. This was done for each year up to 2008. An average was taken of only the years with an increase in centrifugal compressors, up to 2008, to determine the number of new centrifugal compressors in 2008. The result was 16 and 14 new centrifugal compressors in the processing and transmission segments respectively. A summary of the estimates for new centrifugal compressor is presented in Table 6-4.

6.3.4 Emission Estimates

Nationwide baseline emission estimates for new reciprocating and centrifugal compressors are summarized in Table 6-5 by industry segment.

Table 6-5.Nationwide Baseline Emissions for New Reciprocating and Centrifugal Compressors

Industry Segment/ Compressor Type	Nationwide baseline Emissions (tons/year)		
	Methane	VOC	HAP
Reciprocating Compressors			
Production (Well Pads)	1,186	330	12.4
Gathering & Boosting	2,587	719	27.1
Processing	4,871	1,354	51.0
Transmission	529	14.6	0.435
Storage	113	3.13	0.0929
Centrifugal Compressors			
Processing	3,640	329	11.8
Transmission/Storage	1,768	48.9	1.45

6.4 Control Techniques

6.4.1 Potential Control Techniques

The potential control options reviewed for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. This includesreplacement of the compressor rod packing, replacement of the piston rod, and the refitting or realignment of the piston rod.

The replacement of the rod packing is a maintenance task performed on reciprocating compressors to reduce the leakage of natural gas past the piston rod. Over time the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings reduces methane and VOC emissions. Therefore, this control technique was determined to be an appropriate optionfor reciprocating compressors.

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.[14] Rods wear “out-of-round” or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod. This analysis assumes operators will choose, at their discretion, when to replace the rod and hence, does not consider this control technique to be a practical control option for reciprocating compressors. A summary of these techniques are presented in the following sections.

Potential control options to reduce emissions from centrifugal compressors include control techniques that limit the leaking of natural gas across the rotating shaft, or capture and destruction of the emissions using a flare. A summary of these techniques are presented in the following sections.

A control technique for limiting or reducing the emission from the rotating shaft of a centrifugal compressor is a mechanical dry seal system. This control technique uses rings to prevent the escape of natural gas across the rotating shaft. This control technique was determined to be a viable option for reducing emission from centrifugal compressors.

For centrifugal compressors equipped with wet seals, a flare was considered to be a reasonable option for reducing emissions from centrifugal compressors. Centrifugal compressors require seals around the rotating shaft to prevent natural gas from escaping where the shaft exits the compressor casing. "Beam" type compressors have two seals, one on each end of the compressor, while "over-hung" compressors have a seal on only the "inboard" (motor end) side. These seals use oil, which is circulated under high pressure between three rings around the compressor shaft, forming a barrier against the compressed gas leakage. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. The seal also includes "O-ring" rubber seals, which prevent leakage around the stationary rings. The oil barrier allows some gas to escape from the seal, but considerably more gas is entrained and absorbed in the oil under the high pressures at the "inboard" (compressor side) seal oil/gas interface, thus contaminating the seal oil. Seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated back to the seal. As a control measure, the recovered gas would then be sent to a flare or other combustion device.

6.4.2 Reciprocating Compressor Rod Packing Replacement

6.4.2.1 Description

Reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage. As the rings wear, they allow more compressed gas to escape, increasing rod packing emissions. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the "nose gasket" around the packing case, between the packing cups, and between the rings and shaft. If the fit between the rod packing rings and rod is too loose, more compressed gas will escape. Periodically replacing the packing rings ensures the correct fit is maintained between packing rings and the rod.

6.4.2.2 Effectiveness

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The potential emission reductions were calculated by comparing the average rod packing emissionswith the average emissions from newly installed and worn-in rod packing. Since the estimate for newly installed rod packing was intended for larger processing and transmission compressors, this analysis uses the estimate to calculate reductions from only gathering and boosting compressors and not wellhead compressor which are known to be smaller. The calculation for gathering and boosting reductions is shown in Equation 1.

$$R_{WP}^{G\&B} = \frac{Comp_{New}^{G\&B}\left(E_{G\&B} - E_{New}\right) \times C \times O \times 8760}{10^6} \qquad \textbf{Equation 1}$$

where,

$R_{WP}^{G\&B}$ = Potential methane emission reductions from gathering and boosting compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);
$Comp_{New}^{G\&B}$ = Number of new gathering and boosting compressors;
$E_{G\&B}$ = Methane emission factor for gathering and boosting compressors inTable 6-2, in cubic feet per hour per cylinder;
E_{New}=Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[15] for this analysis;
C = Average number of cylinders for gathering and boosting compressors in Table 6-2;
O = Percent of time during the calendar year the average gathering and boosting compressor is in the operating and standby pressurized modes, 79.1%;
8760 = Number of days in a year;
10^6 = Number of cubic feet in a million cubic feet.

For wellhead reciprocating compressors, this analysis calculates a percentage reduction using the transmission emission factor from the 1996 EPA/GRI report and the minimum emissions rate from a newly installed rod packing to determine methane emission reductions. The calculation for wellhead compressor reductions is shown in Equation 2 below.

$$R_{Well} = \frac{Comp_{New}^{Well}\left(E_{Well}\right) \times C \times O \times 8760}{10^6}\left(\frac{E_{Trans} - E_{New}}{E_{Trans}}\right) \qquad \textbf{Equation 2}$$

where,

R_{Well} = Potential methane emission reductions from wellhead compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);
$Comp_{New}^{Well}$ = Number of new wellhead compressors;
E_{Well} = Methane emission factor for wellhead compressors from Table 6-2, cubic feet per hour per cylinder;
C = Average number of cylinders for wellhead compressors in Table 6-2;
O = Percent of time during the calendar year the average gathering and boosting compressor is in the operating and standby pressurized modes, 100%;

E_{Trans} = Methane emissions factor for transmission compressors from Table 6-2 in cubic feet per hour per cylinder;
E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[16] for this analysis;
8760 = Number of days in a year;
10^6 = Number of cubic feet in a million cubic feet.

The emission reductions for the processing, transmission, and storage segments were calculated by multiplying the number of new reciprocating compressors in each segment by the difference between the average rod packing emission factors in Table 6-2 by the average emission factor from newly installed rod packing. This calculation, shown in the Equation 3 below, was performed for each of the natural gas processing, transmission, and storage/LNG sectors.

$$R_{PTS} = \frac{Comp_{New}^{PTS}\left(E_{G\&B} - E_{New}\right) \times C \times O \times 8760}{10^6} \qquad \textbf{\textit{Equation 3}}$$

where,

R_{PTS} = Potential methane emission reductions from processing, transmission, or storage compressors switching from wet seals to dry seals, in million cubic feet per year (MMcf/year);
$Comp_{New}^{PTS}$ = Number of new processing, transmission, or storage compressors;
$E_{G\&B}$ = Methane emission factor for processing, transmission, or storage compressors in Table 6-2, in cubic feet per hour per cylinder;
E_{New}=Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder[17] for this analysis;
C = Average number of cylinders for processing, transmission, or storage compressors in Table 6-2;
O = Percent of time during the calendar year the average processing, transmission, or storage compressor is in the operating and standby pressurized modes, 89.7%, 79.1%, 67.5% respectively;
8760 = Number of days in a year;
10^6 = Number of cubic feet in a million cubic feet.

A summary of the potential emission reductions for reciprocating rod packing replacement for each of the oil and gas segments is shown in Table 6-6. The emissions of VOC and HAP were calculated using the methane emission reductions calculated above the gas composition[18] for each of the segments. Reciprocating compressors in the processing sector were assumed to be used to compress production gas.

Table 6-6.Estimated Annual Reciprocating Compressor Emission Reductions from Replacing Rod Packing

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)			Nationwide Emission Reductions (tons/year)		
		Methane	VOC	HAP	Methane	VOC	HAP
Production (Well Pads)	6,000	0.158	0.0439	0.00165	947	263	9.91
Gathering & Boosting	210	6.84	1.90	0.0717	1,437	400	15.1
Processing	375	18.6	5.18	0.195	3,892	1,082	40.8
Transmission	199	21.7	0.600	0.0178	423	11.7	0.348
Storage	9	21.8	0.604	0.0179	87.3	2.42	0.0718

6.4.2.3 Cost Impacts

Costs for the replacement of reciprocating compressor rod packing were obtained from a Natural Gas Star Lessons Learned document[19] which estimated the cost to replace the packing rings to be $1,620 per cylinder. It was assumed that rod packing replacement would occur during planned shutdowns and maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring becausethe rod packingplacement is based on number of hours that the compressor operates. The replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program. [20] The cost impacts arebased on the replacement of the rod packing 26,000 hours that the reciprocating compressor operates in the pressurized mode. The number of hours used for the cost impacts was determined using a weighted average of the annual percentage that the reciprocating compressors are pressurized for all of the new sources. This weighted hours, on average, per year the reciprocating compressor is pressurized was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. This calculates to an average of 3 years for production compressors, 3.8 years for gathering and boosting compressors, 3.3 years for processing compressors, 3.8 years for transmission compressors, and 4.4 years for storage compressors using the operating factors in Table 6-2. The calculated years were assumed to be the equipment life of the compressor rod packing and were used to calculate the capital recovery factor for each of the segments. Assuming an interest rate of 7 percent, the capital recovery factors were calculated to be 0.3848, 0.3122, 0.3490, 0.3122, and 0.2720 for the production, gathering and boosting, processing, transmission, and storage sectors, respectively. The capital costs were calculated using the average rod packing cost of $1,620 and the average number of cylinders per segment in Table 6-2. The annual costs were calculated using the capital cost and the capital recovery factors. A summary of the capital and annual costs for each of the oil and gas segments is shown in Table 6-7.

Monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement was estimated using a natural gas price of $4.00 per Mcf.[21] This cost was used to calculate theannual cost with gas savings using the methane emission reductions in Table 6-6. The annual cost with savings is shown in Table 6-7 for each of the oil and gas segments. The cost effectiveness for the reciprocating rod packing replacement option is presented in Table 6-7. There is no gas savings cost benefits for transmission and storage facilities, because they do not own the natural gas that is

Table 6-7. Cost Effectiveness for Reciprocating Compressor Rod Packing Replacement

Oil and Gas Segment	Capital Cost ($2008)	Annual Cost per Compressor ($/compressor-year)		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		Without savings	With savings	Without savings	With savings	Without savings	With savings
Production	$6,480	$2,493	$2,457	$56,847	$56,013	$15,802	$15,570
Gathering & Boosting	$5,346	$1,669	$83	$877	$43	$244	$12
Processing	$4,050	$1,413	-$2,903	$273	-$561	$76	-$156
Transmission	$5,346	$1,669	N/A	$2,782	N/A	$77	N/A
Storage	$7,290	$2,276	N/A	$3,766	N/A	$104	N/A

compressed at their compressor stations.

6.4.2.4 Secondary Impacts

The reciprocating compressor rod packing replacement is an option that prevents the escape of natural gas from the piston rod. No wastes should be created, no wastewater generated, and no electricity maintenance and therefore, no travel costs will be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring becausethe rod packing

6.4.3 Centrifugal Compressor Dry Seals

6.4.3.1 Description

Centrifugal compressor dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This gas is pumped between the rings by grooves in the rotating ring. The opposing force of high-pressure gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little gas can leak. While the compressor is operating, the rings are not in contact with each other, and therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.

Dry seals substantially reduce methane emissions. At the same time, they significantly reduce operating costs and enhance compressor efficiency. Economic and environmental benefits of dry seals include:

- Gas Leak Rates. During normal operation, dry seals leak at a rate of 6scfmmethane per compressor.[22] While this is equivalent to a wet seal’s leakage rate at the seal face, wet seals generate additional emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is re-circulated is usually vented to the atmosphere, bringing the total leakage rate for tandem wet seals to 47.7 scfm methane per compressor.[23,24]
- Mechanically Simpler. Dry seal systems do not require additional oil circulation components and treatment facilities.

- Reduced Power Consumption. Because dry seals have no accessory oil circulation pumps and systems, they avoid "parasitic" equipment power losses. Wet seal systems require 50 to 100 kW per hour, while dry seal systems need about 5 kW of power per hour.
- Improved Reliability. The highest percentage of downtime for a compressor using wet seals is due to seal system problems. Dry seals have fewer ancillary components, which translates into higher overall reliability and less compressor downtime.
- Lower Maintenance. Dry seal systems have lower maintenance costs than wet seals because they do not have moving parts associated with oil circulation (e.g., pumps, control valves, relief valves, and the seal oil cost itself).
- Elimination of Oil Leakage from Wet Seals. Substituting dry seals for wet seals eliminates seal oil leakage into the pipeline, thus avoiding contamination of the gas and degradation of the pipeline.

Centrifugal compressors were found in the processing and transmission sectors based on information in the greenhouse gas inventory.[25] Therefore, it was assumed that new compressors would be located in these sectors only.

6.4.3.2 Effectiveness

The control effectiveness of the dry seals was calculated by subtracting the dry seal emissions from a centrifugal compressor equipped with wet seals. The centrifugal compressor emission factors in Table 6-2 were used in combination with an operating factor of 43.6 percent for processing centrifugal compressors and 24.2 percent for transmission centrifugal compressors. The operating factors are used to account for the percent of time in a year that a compressor is in the operating mode. The operating factors for the processing and transmission sectors are based on data in the EPA/GRI study.[26] The wet seals emission factor is an average of 48 different wet seal centrifugal compressors. The dry seal emission factor is based on information from the Natural Gas STAR Program.[27] A summary of the emission reduction from the replacement of wet seals with dry seals is shown in Table 6-8.

6.4.3.3 Cost Impacts

The price difference between a brand new dry seal and brand new wet seal centrifugal compressor is insignificant relative to the cost for the entire compressor. General Electric (GE) stated that a natural gas transmission pipeline centrifugal compressor with dry seals cost between \$50,000 and \$100,000 more than the same centrifugal compressor with wet seals. However, this price difference is only about 1 to 3

Table 6-8. Estimated Annual Centrifugal Compressor Emission Reductions from Replacing Wet Seals with Dry Seals

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (ton/compressor-year)			Nationwide Emission Reductions (ton/year)		
		Methane	VOC	HAP	Methane	VOC	HAP
Transmission/Storage	16	199	18.0	0.643	3,183	287	10.3
Storage	14	110	3.06	0.0908	1,546	42.8	1.27

percent of the total cost of the compressor. The price of a brand new natural gas transmission pipeline centrifugal compressor between 3,000 and 5,000 horsepower runs between $2 million to $5 million depending on the number of stages, desired pressure ratio, and gas throughput. The larger the compressor, the less significant the price difference is between dry seals and wet seals. This analysis assumes the additional capital cost for a dry seal compressor is $75,000. The annual cost was calculatedas the capital recovery of this capital cost assuming a 10-year equipment life and 7 percent interest which came to $10,678 per compressor. The Natural Gas STAR Program estimated that the operation and maintenance savings from the installation of dry seals is $88,300 in comparison to wet seals. Monetary savings associated with the amount of gas saved with the replacement of wet seals with dry seals for centrifugal compressors was estimated using a natural gas price of $4.00 per Mcf.[28] This cost was used to calculate the annual cost with gas savings using the methane emission reductions in Table 6-8. A summary of the capital and annual costs for dry seals is presented in Table 6-9. The methane and VOC cost effectiveness for the dry seal option is also shown in Table 6-9. There is no gas savings cost benefits for transmission and storage facilities, because it is assumed the owners of the compressor station may not own the natural gas that is compressed at the station.

6.4.3.4 Secondary Impacts

Dry seals for centrifugal compressors are an option that prevents the escape of natural gas across the rotating compressor shaft. No wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the installation of dry seals on centrifugal compressors.

6.4.4 Centrifugal Compressor Wet Seals with a Flare

6.4.4.1 Description

Another control option used to reduce pollutant emissions from centrifugal compressors equipped withwet seals is to route the emissions to a combustion device or capture the emissions and route them to afuel system. A wet seal system uses oil that is circulated under high pressure between three rings aroundthe compressor shaft, forming a barrier against the compressed gas. The center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing, pressed against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. Compressed gas becomes absorbed and entrained in the fluid barrier and is removed using a heater, flash tank, or other degassing technique so that the oil can be recirculated back to the wet seal. The removed gas is either

Table 6-9. Cost Effectiveness for Centrifugal Compressor Dry Seals

Oil and Gas Segment	Capital Cost ($2008)	Annual Cost per Compressor ($/compressor-yr)		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		without savings	with O&M and gas savings	without savings	with O&M and gas savings	without savings	with O&M and gas savings
Processing	$75,000	$10,678	-$123,730	$595	-$6,892	$54	-$622
Transmission/Storage	$75,000	$10,678	-$77,622	$3,495	-$25,405	$97	-$703

combusted or released to the atmosphere. The control technique investigated in this section is the use of wet seals with the removed gas sent to an enclosed flare.

6.4.4.2 Effectiveness

Flares have been used in the oil and gas industry to combust gas streams that have VOC and HAP. A flare typically achieves 95 percent reduction of these compounds when operated according to the manufacturer instructions. For this analysis, it was assumed that the entrained gas from the seal oil that is removed in the degassing process would be directed to a flare that achieves 95 percent reduction of methane, VOC, and HAP. The wet seal emissions in Table 6-5 were used along with the control efficiency to calculate the emissions reductions from this option. A summary of the emission reductions is presented in Table 6-10.

6.4.4.3 Cost Impacts

The capital and annual cost of the enclosed flare was calculated using the methodology in the EPA Control Cost Manual.[29] The heat content of the gas stream was calculated using information from the gas composition memorandum.[30] A summary of the capital and annual costs for wet seals routed to a flare is presented in Table 6-11. The methane and VOC cost effectiveness for the wet seals routed to a flare option is also shown in Table 6-12. There is no cost saving estimated for this option because the recovered gas is combusted.

6.4.4.4 Secondary Impacts

There are secondary impacts with the option to use wet seals with a flare. The combustion of the recovered gas creates secondary emissions of hydrocarbons, nitrogen oxide (NO_X), carbon dioxide (CO_2), and carbon monoxide (CO) emissions. A summary of the estimated secondary emission are presented in Table 6-11. No other wastes should be created or wastewater generated.

6.5 Regulatory Options

The affected facility definition for a reciprocating compressor is defined as a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of thedriveshaft. A centrifugal compressor is defined as a piece of equipment that compresses a process gas by means of mechanical rotating vanes or impellers. Therefore these types of compressor would be

Table 6-10. Estimated Annual Centrifugal Compressor Emission Reductions from Wet Seals Routed to a Flare

Oil & Gas Segment	Number of New Sources Per Year	Individual Compressor Emission Reductions (tons/compressor-year)			Nationwide Emission Reductions (tons/year)		
		Methane	VOC	HAP	Methane	VOC	HAP
Processing	16	216	19.5	0.699	3,283	296	10.6
Transmission/Storage	14	120	3.32	0.0986	1,596	44.2	1.31

Table 6-11. Secondary Impacts from Wet Seals Equipped with a Flare

Industry Segment	Secondary Impacts from Wet Seals Equipped with a Flare (tons/year)				
	Total Hydrocarbons	**Carbon Monoxide**	**Carbon Dioxide**	**Nitrogen Oxides**	**Particulate Matter**
Processing	0.0289	0.0205	7.33	0.00377	Negligible
Transmission/Storage	0.00960	0.00889	3.18	0.00163	Negligible

Table 6-12. Cost Effectiveness for Centrifugal Compressor Wet Seals Routed to a Flare

Oil and Gas Segment	Capital Cost ($2008)	Annual Cost per Compressor ($/compressor-year)		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)	
		without savings	with gas savings	without savings	with gas savings	without savings	with gas savings
Processing	$67,918	$103,371	N/A	$5,299	N/A	$478	N/A
Transmission/Storage	$67,918	$103,371	N/A	$31,133	N/A	$862	N/A

subject to a New Performance Standard (NSPS) at the time of installation. The following Regulatory options were evaluated:

- Regulatory Option 1: Require replacement of the reciprocating compressor rod packing based on26,000 hours of operation while the compressor is pressurized.
- Regulatory Option 2: Require all centrifugal compressors to be equipped with dry seals.
- Regulatory Option 3: Require centrifugal compressors equipped with a wet seal to route the recovered gas emissions to a combustion device.

6.5.1 Evaluation of Regulatory Options

The first regulatory option for replacement of the reciprocating compressor rod packing based on the number of hours that the compressor operates in the pressurized mode was described in Section 6.4.1. The VOC cost effectiveness from $56,847 for reciprocating compressors located at production pads to $273 for reciprocating compressors located at processing plants. The VOC cost effectiveness for the gathering and boosting, transmission, and storage segments were $877, $2,782, and 3,766 respectively. Based on these cost effectiveness values, Regulatory Option 1 was accepted for the processing, gathering and boosting, transmission, and storage segments and rejected for the production segment.

The second regulatory option would require all centrifugal compressors to be equipped with dry seals. As presented in Section 6.4.2, dry seals are effective at reducing emissions from the rotating shaft of a centrifugal compressor. Dry seals also reduce operation and maintenance costs in comparison to wet seals. In addition, a vendor reported in 2003 that 90 percent of new compressors that were sold by the company were equipped with dry seals. Another vendor confirmed in 2010 that the rate at which new compressor sales have dry seals is still 90 percent; thus, it was assumed that from 2003 onward, 90 percent of new compressors are equipped with dry seals. The VOC cost effectiveness of dry seals was calculated to be $595 for centrifugal compressors located at processing plants, and $3,495 for centrifugal compressors located at transmission or storage facilities. Therefore, Regulatory Option 2 was accepted as a regulatory option for centrifugal compressors located at processing, transmission, or storage facilities.

The third regulatory option would allow the use of wet seals if the recovered gas emissions were routed to a flare. Centrifugal compressors with wet seals are commonly used in high pressure applications over 3,000 pounds per square inch (psi). None of the applications in the oil and gas industry operate at these pressures. Therefore, it does not appear that any facilities would be required to operate a centrifugal compressor with wet seals. The VOC control effectiveness for the processing and transmission/storage segments were $5,299 and $31,133 respectively. Therefore, Regulatory Option 3 was rejected due to the high VOC cost effectiveness.

6.5.2 Nationwide Impacts of Regulatory Options

Tables 6-13 and 6-14 summarize the impacts of the selected regulatory options by industry segment. Regulatory Option 1 is estimated to affect 210 reciprocating compressors at gathering and boosting stations, 209 reciprocating compressors at processing plants, 20 reciprocating compressors at transmission facilities, and 4 reciprocating compressors at underground storage facilities. A summary of the capital and annual costs and emission reductions for this option is presented in Table 6-13.

Regulatory Option 2 is expected to affect 16 centrifugal compressors in the processing segment and 14 centrifugal compressors in the transmission and storage segments. A summary of the capital and annual costs and emission reductions for this option is presented in Table 6-14.

Table 6-13. Nationwide Cost Impacts for Regulatory Option 1

Oil & Gas Segment	Number of New Sources Per Year	Nationwide Emission Reductions (tons/year)			Total Nationwide Costs		
		VOC	Methane	HAP	Capital Cost ($)	Annual Cost without savings ($/yr)	Annual Cost with savings ($/yr)
Gathering & Boosting	210	400	1,437	15.1	$1,122,660	$350,503	$17,337
Processing	209	1,082	3,892	40.8	$846,450	$295,397	-$606,763
Transmission	20	11.7	423	0.348	$104,247	$32,547	$32,547
Storage	4	2.42	87.3	0.0718	$29,160	$9,104	$9,104

Table 6-14. Nationwide Cost Impacts for Regulatory Option 2

Oil & Gas Segment	Number of New Sources Per Year	Nationwide Emission Reductions[1] (tons/year)			Total Nationwide Costs[a]		
		VOC	Methane	HAP	Capital Cost ($)	Annual Cost w/o Savings ($/year)	Annual Cost w/ Savings ($/year)
Production (Well Pads)	0	0	0	0	0	0	0
Gathering & Boosting	0	0	0	0	0	0	0
Processing	16	118	422	4.42	$100,196	$14,266	-$120,144
Transmission/Storage	14	3.24	117	0.0962	$50,098	$7,133	-$37,017

a. The nationwide emission reduction and nationwide costs are based on the emission reductions and costs for 2 centrifugal compressors with wet seals located a processing facility and 1 centrifugal compressor equipped with wet seal located at a transmission or storage facility.

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7.0 STORAGE VESSELS

Storage vessels, or storage tanks, are sources of air emissions in the oil and natural gas sector. This chapter provides a description of the types of storage vessels present in the oil and gas sector, and provides emission estimates for a typical storage vessel as well as nationwide emission estimates. Control techniques employed to reduce emissions from storage vessels are presented, along with costs, emission reductions, and secondary impacts. Finally, this chapter provides a discussion of considerations used in developing regulatory alternatives for storage vessels.

7.1 Process Description

Storage vessels in the oil and natural gas sector are used to hold a variety of liquids, including crude oil, condensates, produced water, etc. Underground crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface and processed, many of the dissolved lighter hydrocarbons (as well as water) are removed through as series of high-pressure and low-pressure separators. Crude oil under high pressure conditions is passed through either a two phase separator (where the associated gas is removed and any oil and water remain together) or a three phase separator (where the associated gas is removed and the oil and water are also separated). At the separator, low pressure gas is physically separated from the high pressure oil. The remaining low pressure oil is then directedto a storage vessel where it is stored for a period of time before being shipped off-site. The remaining hydrocarbons in the oil are released from the oil as vapors in the storage vessels. Storage vessels are typically installed with similar or identical vessels in a group, referred to in the industry as a tank battery.

Emissions of the remaining hydrocarbons from storage vessels are a function of working, breathing (or standing), and flash losses. Working losses occur when vapors are displaced due to the emptying and filling of storage vessels. 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 vesselfrom a processing vessel operated at a higher pressure. Typically, the larger the pressure drop, the more flash emissions will occur in the storage stage. Temperature of the liquid may also influence the amount of flash emissions.

The volume of gas vapor emitted from a storage vessel depends on many factors. Lighter crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is frequently cycled and the overall throughput is high, working losses are higher. Additionally, the operating temperature and pressure of oil in the separator dumping into the storage vesselwill affect the volume of flashed gases coming out of the oil.

The composition of the vapors from storage vessels varies, and the largest component is methane, but also includes ethane, butane, propane, and hazardous air pollutants (HAP) such as benzene, toluene, ethylbenzene, xylene (collectively referred to as BTEX), and n-hexane.

7.2 Emissions Data

7.2.1 Summary of Major Studies and Emissions

Given the potentially significant emissions from storage vessels, there have been numerous studies conducted to estimate these emissions. Many of these studies were consulted to evaluate the emissions and emission reduction options for emissions from storage vessels. Table 7-1 presents a summary of these studies, along with an indication of the type of information available in each study.

7.2.2 Representative Storage Vessel Emissions

Due to the variability in the sizes and throughputs, model tank batteries were developed to represent the ranges of sizes and population distribution of storage vessels located attank batteries throughout the sector. Model tank batteries were not intended to represent any single facility, but rather a range of facilities with similar characteristics that may be impacted by standards. Model tank batteries were developed for condensate tank batteries and crude oil tank batteries. Average VOC emissions were then developed and applied to the model tank batteries.

7.2.2.1 Model Condensate Tank Batteries

During the development of the national emissions standards for HAP (NESHAP) for oil and natural gas production facilities (40 CFR part 63, subpart HH), model plants were developed to represent condensate tank batteries across the industry.[1]For this current analysis, the most recent inventory data available was the 2008 U.S. Greenhouse Gas Emissions Inventory.[2,3] Therefore, 2008 was chosen to represent the base year for this impacts analysis.To estimate the current condensate battery population and distribution across the model plants, the number of tanks represented by the model plants was scaled

Table 7-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emission Figures	Control Information
VOC Emissions from Oil and Condensate Storage Tanks[4]	Texas Environmental Research Consortium	2009	Regional	X	X
Lessons Learned from Natural Gas STAR Partners:Installing Vapor Recovery Units on Crude Oil Storage Tanks[5]	EPA	2003	National		X
Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation – Final Report[6]	Texas Commission on Environmental Quality	2009	Regional	X	
Initial Economics Impact Analysis for Proposed State Implementation Plan Revisions to the Air Quality Control Commission's Regulation Number [7]	Colorado	2008	n/a		X
E&P TANKS[8]	American Petroleum Institute		National	X	
Inventory of U.S. Greenhouse Gas Emissions and Sinks[2,3]	EPA	2008 and 2009	National	X	

from 1992 (the year for which that the model plants were developed under the NESHAP) to 2008 for this analysis. Based on this approach, it was estimated that there were a total of 59,286 existing condensate tanks in 2008. Condensate throughput data from the U.S. Greenhouse Gas Emissions Inventory was used to scale up from 1992 the condensate tank populations for each model condensate tank battery under the assumption that an increase in condensate production would be accompanied by a proportional increase in number of condensate tanks. The inventory data indicate that condensate production increased from a level of 106 million barrels per year (MMbbl/yr) in 1992to 124 MMbbl/yr in 2008.This increase in condensate production was then distributed across the model condensate tank batteriesin the same proportion as was done for the NESHAP. The model condensate tank batteries are presented in Table 7-2.

7.2.2.2 Model Crude Oil Tank Batteries

According to the Natural Gas STAR program,[5] there were 573,000 crude oil storage tanksin 2003. According to the U.S. Greenhouse Gas Emissions Inventory, crude oil production decreased from 1,464 MMbbl/yr in 2003 to 1,326 MMbbl/yr (a decrease of approximately 9.4 percent) in 2008. Therefore, it was assumed that the number of crude oil tanks in 2008 were approximately 90.6 percent of the number of tanks identified in 2003. Therefore, for this analysis it was assumed that there were 519,161 crude oil storage tanks in 2008. During the development of the NESHAP, model crude oil tank batteries were not developed and a crude oil tank population was not estimated. Therefore, it was assumed that the percentage distribution of crude oil storage tanks across the four model crude oil tank battery classifications was the same as for condensate tank batteries.Table 7-3 presents the model crude oil tank batteries.

7.2.2.3 VOC Emissions from Condensate and Crude Oil Storage Vessels

Once the modelcondensate and crude oil tank battery distributionswere developed, VOC emissions from a representative storage vessel were estimated. Emissions from storage vessels vary considerably depending on many factors, including, but not limited to, throughput, API gravity, Reid vapor pressure, separator pressure, etc. The American Petroleum Institute (API) has developed a software program called E&P TANKS which contains a dataset of more than 100 storage vessels from across the country.[8] A summary of the information contained in the dataset, as well as the output from the E&P TANKS program, is presented in Appendix A of this document. According to industry representatives, this

Table 7-2. Model Condensate Tank Batteries

	Model Condensate Tank Battery			
Parameter	**E**	**F**	**G**	**H**
Condensate throughput (bbl/day)[a]	15	100	1,000	5,000
Condensate throughput (bbl/yr) [a]	5,475	36,500	365,000	1,825,000
Number of fixed-roof product storage vessels [a]				
210 barrel capacity	4	2		
500 barrel capacity		2	2	
1,000 barrel capacity			2	4
Estimated tank battery population (1992)[a]	12,000	500	100	70
Estimated tank battery population (2008) [b]	14,038	585	117	82
Total number of storage vessels (2008) [b]	56,151	2,340	468	328
Percent of number of storage vessels in model condensate tank battery	94.7%	3.95%	0.789%	0.552%
Percent of throughput per model condensate tank battery[a]	26%	7%	15%	51%
Total tank battery condensate throughput (MMbbl/yr)[c]	32.8	9.11	18.2	63.8
Condensate throughput per model condensate battery (bbl/day)	6.41	42.7	427	2,135
Condensate throughput per storage vessel (bbl/day)	1.60	10.7	106.8	534

Minor discrepancies may be due to rounding.

a. Developed for NESHAP (Reference 1).
b. Population of tank batteries for 2008 determined based on condensate throughput increase from 106 MMbbl/yr in 1992 to 124 MMbbl/yr in 2008 (References2,3).
c. 2008 condensate production rate of 124 MMbbl/yr distributed across model tank batteries using same relative ratio as developed for NESHAP (Reference 1).

Table 7-3. Model Crude Oil Tank Batteries

	Model Crude Oil Tank Battery			
Parameter	**E**	**F**	**G**	**H**
Percent of number of condensate storage vessels in model size range[a]	94.7%	3.95%	0.789%	0.552%
Number of storage vessels[b]	491,707	20,488	4,098	2,868
Percent of throughput across condensate tank batteries	26%	7%	15%	51%
Crude oil throughput per model plant category (MMbbl/yr)	351	97.5	195	683
Crude oil throughput per storage vessel (bbl/day)	1.96	13.0	130	652

Minor discrepancies may be due to rounding.

a. Same relative percent of storage vessel population developed for model condensate tank batteries.Refer to Table 7-2.
b. Calculated by applying the percent of number of condensate storage vessels in model size range to total number of crude oil storage vessels (519,161 crude oil storage vessels estimated for 2008) (Reference 5).
c. Same relative percent of throughput developed for model condensate tank batteries.Refer to Table 7-2.

dataset in combination with the output of the E&P TANKS program is representative of the various VOC emissions from storage vessels across the country.[9]

The more than 100 storage vesselsprovided with the E&P TANKS program, which had varying characteristics, were modeled with a constant throughput (based on the assumption that emissions would increase in proportion with throughput) and the relationship of these different characteristics and emissionswas studied. While many of the characteristics impacted emissions, a correlation was found to exist between API gravity and emissions. The average API gravity for all storage vessels in the data set was approximately 40 degrees. Therefore, we selected an API gravity of 40 degrees as a parameter to distinguish between lower emitting storage vessels and higher emitting storage vessels.[i] While the liquid type was not specified for the storage vessels modeled in the study, it was assumed that condensate storage vessels would have higher emissions than crude oil storage vessels. Therefore, based on this study using the E&P TANKS program, it was assumed for this analysis that liquids with API gravity equal to or greater than 40 degrees should be classified as condensate and liquids with API gravity less than 40 degrees should be classified as crude oil.

The VOC emissions from all storage vessels in the analysis are presented in Appendix A.Table 7-4 presents a summary of the average VOC emissions from all storage vessels as well as the average VOC emissions from the storage vessels identified as being condensate storage vessels and those identified as being crude oil storage vessels. As shown in Table 7-4, the storage vessels were modeled at a constant throughput of 500 bpd.[ii]An average emission factor was developed for each type of liquid. The average of condensate storage vessel VOC emissions was modeled to be 1,046 tons/year or 11.5 lb VOC/bbl and the average of crude oil storage vessel VOC emissions was modeled to be 107 tons/year or 1.18 lb VOC/bbl. These emission factors were then applied to each of the two sets of model storage vessels in Tables 7-2 and 7-4 to develop the VOC emissions from the model tank batteries. These are presented in Table 7-5.

[i] The range of VOC emissions within the 95 percent confidence interval for storage vessels with an API gravity greater than 40 degrees was from 667 tons/year to 1425 tons/year. The range for API gravity less than 40 degrees was 76 tons/year to 138.
[ii] This throughput was originally chosen for this analysis to be equal to the 500 bbl/day throughput cutoff in subpart HH. While not part of the analysis described in this document, one of the original objectives of the E&P TANKS analysis was to assess the level of emissions associated with a storage vessel with a throughput below this cutoff. Due to the assumption that emissions increase and decrease in proportion with throughput, it was decided that using a constant throughput of 500 bbl/day would still provide the information necessary to determine VOC emissions from model condensate and crude oil storage vessels for this document.

Table 7-4. Summary of Data from E&P TANKS Modeling

Parameter[a]		Average of Dataset	Average of Storage Vessels with API Gravity > 40 degrees	Average of Storage Vessels with API Gravity $\leq$ 40 degrees
Throughput Rate (bbl)		500	500	500
API Gravity		40.6	52.8	30.6
VOC	Emissions (tons/year)	531	1046	107
	Emission factor (lb/bbl)	5.8	11.5	1.18

a. Information from analysis of E&P Tanks dataset, refer to Appendix A.

Table 7-5. Model Storage Vessel VOC Emissions

Parameter	Model Tank Battery			
	E	F	G	H
Model Condensate Tank Batteries				
Condensate throughput per storage vessel (bbl/day)	1.60	10.7	107	534
VOC Emissions (tons/year)[b]	3.35	22.3	223	1117
Model Crude Oil Tank Batteries				
Crude Oil throughput per storage vessel (bbl/day)[c]	2.0	13	130	652
VOC Emissions (tons/year)[d]	0.4	2.80	28	140

a. Condensate throughput per storage vessel from table 7-2.

b. Calculated using the VOC emission factor for condensate storage vessels of 11.5 lb VOC/bbl condensate.

c. Crude oil throughput per storage vessel from table 7-3.

d. Calculated using the VOC emission factor for crude oil storage vessels of 1.18 lb VOC/bbl crude oil.

7.3 Nationwide Baseline Emissions from New or Modified Sources

7.3.1 Overview of Approach

The first step in this analysis is to estimate nationwide emissions in absence of a federal rulemaking, referred to as the nationwide baseline emissions estimate. In order to develop the baseline emissions estimate, the number of new storage vessels expected in a typical year was calculated and then multiplied by the expected uncontrolled emissions per storage vessels presented in Table 7-5. In addition, to ensure no emission reduction credit was attributed to new sources that would already be required to be controlled under State regulations, it was necessary to account for the number of storage vessels already subject to State regulations as detailed below.

7.3.2 Number of New Storage Vessels Expected to be Constructed or Reconstructed

The number of new storage vessels expected to be constructed was determined for the year 2015 (the year of analysis for the regulatory impacts). To do this, it was assumed that the number of new or modified storage vessels would increase in proportion with increases in production. The Energy Information Administration (EIA), published crude oil production rates up to the year 2011.[10]Therefore, using the forecast function in Microsoft Excel® , crude oil production was predicted for the year 2015.[iii] From 2009 to 2015,[iv] the expected growth of crude oil production was projected to be 8.25 percent (from 5.36 bpd to 5.80 bpd). Applying this expected growth to the number of existing storage vessels results in an estimate of 4,890 new or modified condensate storage vessels and 42,811 new or modified crude oil storage vessels. The number of new or modified condensate and crude oil storage vessels expected to be constructed or reconstructed is presented in Table 7-6.

7.3.3 Level of Controlled Sources in Absence of Federal Regulation

As stated previously, to determine the impact of a regulation, it was first necessary to determine the current level of emissions from the sources being evaluated, or baseline emissions. To more accurately estimate baseline emissions for this analysis, and to ensure no emission reduction credit was attributed

[iii] The crude oil production values published by the EIA include leased condensate. Therefore, the increase in crude oil production was assumed to be valid for both crude oil and condensate tanks for the purpose of this analysis.
[iv] For the purposes of estimating growth, the crude oil production rate in the year 2008 was considered an outlier for production and therefore was not used in this analysis.

Table 7-6. Nationwide Baseline Emissions for Storage Vessels

	Model Tank Battery				
	E	**F**	**G**	**H**	**Total**
Model Condensate Tank Batteries					
Total number of storage vessels (2008)	56,151	2,340	468	328	59,286
Total projected number of new or modified storage vessels (2015) [a]	4,630	193	39	27	4,889
Number of uncontrolled storage vessels in absence of federal regulation[b]	1,688	70	14	10	1,782
Uncontrolled VOC Emissions from storage vessel at model tank battery[c]	3.35	22.3	223	1,117	1,366
Total Nationwide Uncontrolled VOC Emissions	5,657	1,572	3,143	11,001	21,373
Model Crude Oil Tank Batteries					
Total number of storage vessels (2008)	491,707	20,488	4,098	2,868	519,161
Total projected number of new or modified storage vessels (2015) [a]	40,548	1,689	338	237	42,812
Number of uncontrolled storage vessels in absence of federal regulation[b]	14,782	616	123	86	15,607
Uncontrolled VOC Emissions from storage vessel at model tank battery[c]	0.4	2.80	28	140	171
Total Nationwide Uncontrolled VOC Emissions	6,200	1,722	3,444	12,055	23,421

Minor discrepancies may be due to rounding

a. Calculated by applying the expected 8.25 percent industry growth to the number of storage vessels in 2008.
b. Calculated by applying the estimated 36 percent of storage vessels that are uncontrolled in the absence of a Federal Regulation to the total projected number of new or modified storage vessels in 2015.
c. VOC Emissions from individual storage vessel at model tank battery, see Table 7-5.

for sources already being controlled, it was necessary to determine which storage vessels were already being controlled. To do this, the 2005 National Emissions Inventory (NEI) was used.Storage vessels in the oil and natural gas sector were identified under the review of the maximum achievable control technology (MACT) standards.[11] There were 5,412 storage vessels identified in the NEI, and of these, 1,973 (or 36 percent) were identified as being uncontrolled. Therefore, this percent of storage vessels that would not require controls under State regulations was applied to the number of new or modified storage vessels results in an estimate of 1,782 new or modified condensate storage vessels and 15,607 new or modified crude oil storage vessels.These are also presented in Table 7-6.

7.3.4 Nationwide Emission Estimates for New or Modified Storage Vessels

Nationwide emissions estimates are presented in Table 7-6 for condensate storage vessels and crude oil storage vessels. Model storage vessel emissions were multiplied by the number of expected new or modified storage vessels that would be uncontrolled in the absence of a federal regulation.As shown in Table 7-6, the baseline nationwide emissions are estimated to be 21,373 tons/year for condensate storage vessels and 23,421 tons/year for crude oil storage vessels.

7.4 Control Techniques

7.4.1 Potential Control Techniques

In analyzing controls for storage vessels, we reviewed control techniques identified in the Natural Gas STAR program and state regulations. We identified two ways of controlling storage vessel emissions, both of which can reduce VOC emissions by 95 percent. One option would be to install a vapor recovery unit (VRU) and recover all the vapors from the storage vessels. The other option would be to route the emissions from the storage vessels to a combustor. These control technologies are described below along with their effectiveness as they apply to storage vessels in the oil and gas sector, cost impacts associated with the installation and operation of these control technologies, and any secondary impacts associated with their use.

7.4.2 Vapor Recovery Units

7.4.2.1 Description

Typically, with a VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator, or suction scrubber, to collect any condensed liquids, which are typically recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system. Vapors are then either sent to the pipeline for sale or used as on-site fuel.[5]

7.4.2.2 Effectiveness

Vapor recovery units have been shown to reduce VOC emissions from storage vessels by approximately 95 percent.***Error! Bookmark not defined.***A VRU recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold.If natural gas is recovered, it can be sold as well, as long as a gathering line is available to convey the recovered salable gas product to market or to further processing. A VRU also does not have secondary air impacts, as described below. However, a VRU cannot be used in all instances. Some conditions that affect the feasibility of VRU are: availability of electrical service sufficient to power the compressor; fluctuations in vapor loading caused by surges in throughput and flash emissions from the storage vessel; potential for drawing air into condensate storage vessels causing an explosion hazard; and lack of appropriate destination or use for the vapor recovered.

7.4.2.3 Cost Impacts

Cost data for a VRU was obtained from an Initial Economic Impact Analysis (EIA) prepared for proposed state-only revisions to a Colorado regulation.Cost information contained in the EIA was assumed to be giving in 2007 dollars.[7]Therefore costs were escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4).[12] According to the EIA, the purchased equipment cost of a VRU was estimated to be $85,423 (escalated to 2008 dollars from $75,000 in 2007 dollars). Total capital investment, including freight and design and installation was estimated to be $98,186. These cost data are presented in Table 7-7. Total annual costs were estimated to be $18,983/year.

7.4.2.4 Secondary Impacts

A VRU is a pollution prevention technique that is used to recover natural gas that would otherwise be emitted. No secondary emissions (e.g., nitrogen oxides, particulate matter, etc.) would be generated, no wastes should be created, no wastewater generated, and no electricity needed. Therefore, there are no secondary impacts expected due to the use of a VRU.

Table 7-7. Total Capital Investment and Total Annual Cost of a Vapor Recovery Unit

Cost Item[a]	Capital Costs ($)	Non-Recurring, One-time Costs ($)	Total Capital Investment ($)[b]	O&M Costs ($)	Savings due to Fuel Sales ($/yr)	Annualized Total Cost ($/yr)[c]
VRU	$78,000					
Freight and Design		$1,500				
VRU Installation		$10,154				
Maintenance				$8,553		
Recovered natural gas					($1,063)	
Subtotal Costs (2007)	$78,000	$11,654		$8,553	($1,063)	
Subtotal Costs (2008)[d]	$85,423	$12,763	$98,186	$9,367	($1,164)	
Annualized costs (using 7% interest, 15 year equipment life)	$9,379	$1,401		n/a	n/a	$18,983

Minor discrepancies may be due to rounding

a. Assume cost data provided is for the year 2007. Reference 7.
b. Total Capital Investment is the sum of the subtotal costs for capital costs and nonrecurring one-time costs.
c. Total Annual Costs is the sum of the annualized capital and recurring costs, O&M costs, and savings due to fuel sales.
d. Costs are escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4). Reference 12.

7.4.3 Combustors

7.4.3.1 Description and Effectiveness

Combustors are also used to control emissions from condensate and crude oil storage vessels.The type of combustor used is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, found in waste streams.[13] Combustors are used to control VOC in many industrial settings, since thecombustorcan normally handle fluctuations in concentration, flow rate, heating value, and inert species content.[14] For this analysis, the types of combustors installed for the oil and gas sector are assumed to achieve 95 percent efficiency.[7] Combustors do not have the same operational issues as VRUs, however secondary impacts are associated with combustors as discussed below.

7.4.3.2 Cost Impacts

Cost data for a combustor was also obtained from the Initial EIA prepared for proposed state-only revisions to the Colorado regulation.[7] As performed for the VRU, costs were escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4).[12] According to the EIA, the purchased equipment cost of a combustor, including an auto igniter and surveillance system was estimated to be $23,699 (escalated to 2008 dollars from $21,640 in 2007 dollars). Total capital investment, including freight and design and installation was estimated to be $32,301. These cost data are presented in Table 7-8. Total annual costs were estimated to be $8,909/year.

7.4.3.3 Secondary Impacts

Combustion and partial combustion of many pollutants also create secondary pollutants including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide, and smoke/particulates. Reliable data for emission factors from combustors on condensate and crude oil storage vessels are limited. Guidelines published in AP-42 for flare operations are based on tests from a mixture containing 80 percent propylene and 20 percent propane.[13] These emissions factors, however, are thebest indication for secondary pollutants from combustors currently available. The secondary emissionsper storage vessel are provided in Table 7-9.

Table 7-8. Total Capital Investment and Total Annual Cost of a Combustor

Cost Item[a]	Capital Costs ($)	Non-Recurring, One-time Costs ($)	Total Capital Investment ($)[b]	O&M Costs ($)	Annualized Total Cost ($/yr)[c]
Combustor	$16,540				
Freight and Design		$1,500			
Combustor Installation		$6,354			
Auto Igniter	$1,500				
Surveillance System[d]	$3,600				
Pilot Fuel				$1,897	
Maintenance				$2,000	
Data Management				$1,000	
Subtotal Costs (2007)	$21,640	$7,854		$4,897	
Subtotal Costs (2008)[e]	$23,699	$8,601	$32,301	$5,363	
Annualized costs (using 7% interest, 15 year equipment life)	$2,602	$944		n/a	$8,909

Minor discrepancies may be due to rounding

a. Assume cost data provided is for the year 2007. Reference 7.
b. Total Capital Investment is the sum of the subtotal costs for capital costs and nonrecurring one-time costs.
c. Total Annual Costs is the sum of the annualized capital and recurring costs, O&M costs, and savings due to fuel sales.
d. Surveillance system identifies when pilot is not lit and attempt to relight it, documents the duration of time when the pilot is not lit, and notifies and operator that repairs are necessary.
e. Costs are escalated to 2008 dollars using the CE Indices for 2007 (525.4) and 2008 (575.4). Reference 12.

Table 7-9. Secondary Impacts for Combustors used to Control Condensate and Crude Oil Storage Vessels

Pollutant	Emission Factor	Units	Emissions per Storage Vessel (tons/year)[a]
THC	0.14	lb/MMBtu	0.0061
CO	0.37	lb/MMBtu	0.0160
CO_2	60	Kg/MMBtu[b]	5.62
NO_X	0.068	lb/MMBtu	2.95E-03
PM	40	µg/l (used lightly smoking flares due to criteria that flares should not have visible emissions i.e. should not smoke)	5.51E-05

a. Converted using average saturated gross heating value of the storage vessel vapor (1,968 Btu/scf) and an average vapor flow rate of 44.07 Mcf per storage vessel. See Appendix A.
b. CO_2 emission factor obtained from 40 CFR Part 98, subpart Y, Equation Y-2.

7.5 Regulatory Options and Nationwide Impacts of Regulatory Options

7.5.1 Consideration of Regulatory Options for Condensate and Crude Oil Storage Vessels

The VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (i.e., its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid's volatility and temperature of the liquid.Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric pressure. Therefore, in order to determine the most cost effective means of controlling the storage vessels, a cutoff was evaluated to limit the applicability of the standards to these storage vessels. Rather than require a cutoff in terms of emissions that would require a facility to conduct an emissions test on their storage vessel, a throughput cutoff was evaluated. It was assumed that facilities would have storage vessel throughput data readily available. Therefore, we evaluated the costs of controlling storage vessels with varying throughputs to determine which throughput level would provide the most cost effective control option.

The standard would require an emission reduction of 95 percent, which, as discussed above, could be achieved with a VRU or a combustor. A combustoris an option for tank batteries because of the operational issues associated with a VRU as discussed above.However the use of a VRU is preferable to a combustorbecause a combustordestroys, rather than recycles, valuable resources and there are secondary impacts associated with the use of a combustor. Therefore, the cost impacts associated a VRU installed for the control of storage vessels were evaluated.

To conduct this evaluation, emission factor data from a study prepared for the Texas Environmental Research Consortium[15] was used to represent emissions from the different throughputs being evaluated. For condensate storage vessels, an emission factor of 33.3 lb VOC/bbl was used and for crude oil storage vessels, an emission factor of 1.6 lb VOC/bbl was used.Using the throughput for each control option, an equivalent emissions limit was determined.Table 7-10 presents the following regulatory options considered for condensate storage vessels:

- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 0.5 bbl/day (equivalent emissions of 3.0 tons/year);

Table 7-10. Options for Throughput Cutoffs for Condensate Storage Vessels

Regulatory Option	Throughput Cutoff (bbl/day)	Equivalent Emissions Cutoff (tons/year) [a]	Emission Reduction (tons/year) [b]	Annual Costs for VRU ($/yr) [c]	Cost Effectiveness ($/ton)	Number of impacted units[d]
1	0.5	3.0	2.89	$18,983	$6,576	1782
2	1	6.1	5.77	$18,983	$3,288	94
3	2	12.2	11.55	$18,983	$1,644	94
4	5	30.4	28.87	$18,983	$658	24

Minor discrepancies may be due to rounding

a. Emissions calculated using emission factor of 33.3 lb VOC/bbl condensate and the throughput associated with each option.
b. Calculated using 95 percent reduction
c. Refer to Table 7-7 for VRU Annual Costs.
d. Number of impacted units determined by evaluating which of the model tank batteries and storage vessel populations associated with each model tank battery (refer to Table 7-6) would be subject to each regulatory option. A storage vessel at a model tank battery was considered to be impacted by the regulatory option if its throughput and emissions were greater than the cutoffs for the option.

- Regulatory Option 2: Control condensate storage vessels with a throughput greater than 1 bbl/day (equivalent emissions of 6 tons/year);

- Regulatory Option 3: Control condensate storage vessels with a throughput greater than 2 bbl/day (equivalent emissions of 12 tons/year);

- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 5.0 bbl/day (equivalent emissions of 30 tons/year);

As shown in Table 7-10, Regulatory Option 1 is not cost effective for condensate storage vessels with a throughput of 0.5 bbl/day.Therefore Regulatory Option 1 is rejected.Since the cost effectiveness associated with Regulatory Option 2 is acceptable ($3,288/ton), this option was selected. As shown in Table 7-5, Model Condensate Storage Vessel Categories F, G, and H have throughputs greater than 1 bbl/day and emissions greater than 6 tons/year. Therefore, for the purposes of determining impacts, the populations of new and modified condensate storage vessels associated with categories F, G, and H are assumed to be required to reduce their emissions by 95 percent, a total of 94 new or modified condensate storage vessels.

A similar evaluation was performed for crude oil vessels and is presented in Table 7-11 for the following regulatory options:

- Regulatory Option 1: Control crude oil storage vessels with a throughput greater than 1 bbl/day (equivalent emissions of 0.3 tons/year);

- Regulatory Option 2: Control condensate storage vessels with a throughput greater than 5 bbl/day (equivalent emissions of 1.5 tons/year);

- Regulatory Option 3: Control condensate storage vessels with a throughput greater than 20 bbl/day (equivalent emissions of 6 tons/year);

- Regulatory Option 1: Control condensate storage vessels with a throughput greater than 50 bbl/day (equivalent emissions of 15 tons/year);

As shown in Table 7-11, Regulatory Options 1 and 2 are not cost effective crude oil storage vessels with a throughput of 1 and 5 bbl/day, respectively. Therefore Regulatory Options 1 and 2 are rejected.Since the cost effectiveness associated with Regulatory Option 3 is acceptable ($3,422/ton), this option was selected. As shown in Table 7-5, Model Crude Oil Storage Vessel CategoriesG and H have throughputs greater than 20 bbl/day and emissions greater than 6 tons/year. Therefore, for the purposes of determining impacts, the populations of new and modified crude oil storage vessels associated with categories G

Table 7-11. Options for Throughput Cutoffs for Crude Oil Storage Vessels

Regulatory Option	Throughput Cutoff (bbl/day)	Equivalent Emissions Cutoff (tons/year) [a]	Emission Reduction (tons/year) [b]	Annual Costs for VRU ($/yr) [c]	Cost Effectiveness ($/ton)	Number of impacted units[d]
1	1	0.3	0.28	$18,983	$68,432	15607
2	5	1.5	1.4	$18,983	$13,686	825
3	20	5.8	5.55	$18,983	$3,422	209
4	50	14.6	13.87	$18,983	$1,369	209

Minor discrepancies may be due to rounding

a. Emissions calculated using emission factor of 1.6 lb VOC/bbl condensate and the throughput associated with each option.
b. Calculated using 95 percent reduction
c. Refer to Table 7-7 for VRU Annual Costs.
d. Number of impacted units determined by evaluating which of the model tank batteries and storage vessel populations associated with each model tank battery (refer to Table 7-6) would be subject to each regulatory option. A storage vessel at a model tank battery was considered to be impacted by the regulatory option if its throughput and emissions were greater than the cutoffs for the option.

and H are assumed to be required to reduce their emissions by 95 percent, a total of 209 new or modified condensate storage vessels.

7.5.2 Nationwide Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (i.e., emission reductions), cost impacts and secondary environmental impacts related to Regulatory Option 2 for condensate storage vessels and Regulatory Option 3 for crude oil storage vessels which were selected as viable options for setting standards for storage vessels.In addition, combined impacts for a typical storage vessel are presented.

7.5.3 Primary Environmental Impacts of Regulatory Options

Regulatory Option2 (condensate storage vessels) and 3 (crude oil storage vessels) were selected as options for setting standards for storage vessels as follows:

- Regulatory Option 2 (Condensate Storage Vessels): Reduce emissions from condensate storage vessels with an average throughput greater than 1 bbl/day.

- Regulatory Option 3 (Crude Oil Storage Vessels): Reduce emissions from crude oil storage vessels with an average throughput greater than 20 bbl/day.

The number of storage vessels that would be subject to the regulatory options listed above are presented in Tables7-10 and 7-11. It was estimated that there would be 94 new or modified condensate storage vessels not otherwise subject to State regulationsand impacted by Regulatory Option 2 (condensate storage vessels).As shown in Table 7-11, 209 new or modified crude oil storage vessels not otherwise subject to State regulations would be impacted by Regulatory Option 3 (crude oil storage tanks).

Table 7-12 presents the nationwide emission reduction estimates for each regulatory option. Emissions reductions were estimated by applying 95 percent control efficiency to the VOC emissions presented in Table 7-6 for each storage vessel in the model condensate and crude oil tank batteries and multiplying by the number of impacted storage vessels. For Regulatory Option 2 (condensate storage vessels), the total nationwide VOC emission reduction was estimated to be 15,061 tons/year and 14,710 tons/year for Regulatory Option 3 (crude oil storage vessels).

Table 7-12. Nationwide Impacts of Regulatory Options

Model Tank Battery	Number of Sources subject to Regulatory Option[a]	VOC Emissions for a Typical Storage Vessel (tons/year)	Capital Cost forTypical Storage Vessel[b] ($)	Annual Cost for a Typical Storage Vessel[b] ($/yr)		Nationwide Emission Reductions (tons/year)[c]		VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
				without savings	with savings	VOC	Methane[d]	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 2: Condensate Storage Vessels														
F	70	22.3	65,243	14,528	13,946	1,483	325	685	658	3129	3004	4.57	1.02	0.98
G	14	223	65,243	14,528	13,946	2,966	649	68	66	313	301	0.913	0.203	0.195
H	10	1117	65,243	14,528	13,946	10,612	2,322	14	13	62.6	60.1	0.652	0.145	0.139
Total for Regulatory Option 2						**15,061**	**3,296**					**6.14**	**1.37**	**1.31**
Regulatory Option 3: Crude Oil Storage Vessels														
G	123	28	65,243	14,528	13,946	3,272	716	546	524	2496	2396	8.02	1.79	1.71
H	86	140	65,243	14,528	13,946	11,438	2,503	109	104	499	479	5.61	1.25	1.20
Total for Regulatory Option 3						**14,710**	**3,219**					**13.6**	**3.04**	**2.91**
Combined Impacts[e]														
Typical Storage Vessel	**304**	**103**	**65,243**	**14,528**	**13,946**	**29,746**	**6,490**	**149**	**143**	**680**	**652**	**19.8**	**4.41**	**4.24**

Minor discrepancies may be due to rounding

a. Number of storage vessels in each model tank battery (refer to Table 7-6) determined to be subject to the regulatory option as outlined in Table 7-10.

b. It was assumed for the purposes of estimating nationwide impacts that 50 percent of facilities would install a combustor and 50 percent a VRU.This accounts for the operational difficulties of using a VRU. Capital and Annual Costs determined using the average of costs presented in Tables 7-7 and 7-8.

c. Nationwide emission reductions calculated by applying a 95 percent emissions reduction to the VOC emissions for a typical storage vessel multiplied by the number of sources subject to the regulatory option.

d. Methane Reductions calculated by applying the average Methane to VOC factor from the E&P Tanks Study (see Appendix A).Methane:VOC = 0.219

e. For purposes of evaluating NSPS impact, impacts were determined for an average storage vessel by calculating total VOC emissions from all storage vessels and dividing by the total number of impacted storage vessels to obtain the average VOC emissions per storage vessel.

7.5.4 Cost Impacts

Cost impacts of the individual control techniques (VRU and combustors) were presented in Section 7.4. For both regulatory options, it was assumed that 50 percent of facilities would install a combustor and 50 percent a VRU. This accounts for the operational difficulties of using a VRU. Therefore, the average capital cost of control for each storage vessel was estimated to be $65,243 (the average of the total capital investment for a VRU of $98,186 and $32,301 for a combustor from Tables 7-7 and 7-8, respectively). Similarly, the average annual cost for a typical storage vessel was estimated to be $14,528/yr (average of the total annual cost for a VRU of $20,147/yr and $8,909/yr for a combustor from Tables 7-7 and 7-8, respectively) without including any cost savings due to fuel sales and $13,946/yr (average of the total annual cost for a VRU of $18,983/yr and $8,909/yr for a combustorfrom Tables 7-7 and 7-8, respectively) including cost savings.

Nationwide capital and annual costs were calculated by applying the number of storage vessels subject to the regulatory option. As shown in Table 7-12, the nationwide capital cost of Regulatory Option 2 (condensate storage vessels) was estimated to be $6.14 million and for RegulatoryOption 3 (crude oil storage vessels) nationwide capital cost was estimated to be $13.6 million.Total annual costs without fuel savings were estimated to be $1.37 million/yr for Regulatory Option 2 (condensate storage vessels) and $3.04 million/yr for Regulatory Option 3 (crude oil storage vessels). Total annual costs with fuel savings were estimated to be $1.31 million/yr for Regulatory Option 2 (condensate storage vessels) and $2.91 million/yr for Regulatory Option 3 (crude oil storage vessels).

For purposes of evaluating the impact of a federal standard, impacts were determined for an average storage vessel by calculating the total VOC emissions from all storage vessels and dividing by the total number of impacted storage vessels (304) to obtain the average VOC emissions per storage vessel (103 tons/year).Therefore, the nationwide annual costs were estimated to be $4.41 million/yr. A total nationwide VOC emission reduction of 29,746 tons/year results in a cost effectiveness of $149/ton.

7.5.5 Nationwide Secondary Emission Impacts

Regulatory Options 2 (condensate storage vessels) and 3 (crude oil storage vessels) allow for the use of a combustor; therefore the estimated nationwide secondary impacts are a result of combusting 50 percent of all storage vessel emissions. The secondary impacts for controlling a single storage vessel using a combustor are presented in Table 7-9. Nationwide secondary impacts are calculated by

Table 7-13. Nationwide Secondary Combined Impacts for Storage Vessels

Pollutant	Emissions per Storage Vessel (tons/year) [a]	Nationwide Emissions (tons/year)[b]
THC	0.0061	0.927
CO	0.0160	2.43
CO_2	5.62	854
NO_X	2.95E-03	0.448
PM	5.51E-05	0.0084

a. Emissions per storage vessel presented in Table 7-9.
b. Nationwide emissions calculated by assuming that 50 percent of the 304 impacted storage vessels would install a combustor.

multiplying 50 percent of the estimated number of impacted storage vessels (152) by the secondary emissions and are presented in Table 7-13.

7.6 References

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8.0 EQUIPMENT LEAKS

Leaks from components in the oil and natural gas sector are a source of pollutant emissions. This chapter explains the causes for these leaks, and provides emission estimates for "model" facilities in the various segments of the oil and gas sector. In addition, nationwide equipment leak emission estimates from new sources are estimated. Programs that are designed to reduce equipment leak emissions are explained, along with costs, emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for equipment leaks.

8.1 Equipment Leak Description

There are several potential sources of equipment leak emissions throughout the oil and natural gas sector. 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. The following sub-sections describe potential equipment leak sources and the magnitude of the volatile emissions from typical facilities in the oil and gas industry.

Due to the large number of valves, pumps, and other components within oil and natural gas production, processing, and/or transmission facilities, total equipment leak VOC emissions from these components can be significant. Tank batteries or production pads are generally small facilities as compared with other oil and gas operations, and are generally characterized by a small number of components. Natural gas processing plants, especially those using refrigerated absorption, and transmission stations tend to have a large number of components.

8.2. Equipment leak Emission Data and Emissions Factors

8.2.1 Summary of Major Studies and Emission Factors

Emissions data from equipment leaks have been collected from chemical manufacturing and petroleum production to develop control strategies for reducing HAP and VOC emissions from these sources.[1,2,3] In the evaluation of the emissions and emission reduction options for equipment leaks, many of these studies were consulted. Table 8-1 presents a list of the studies consulted along with an indication of the type of information contained in the study.

8.2.2 Model Plants

Facilities in the oil and gas sector can consist of a variety of combinations of process equipment and components. This is particularly true in the production segment of the industry, where “surface sites” can vary from sites where only a wellhead and associated piping is located to sites where a substantial amount of separation, treatment, and compression occurs. In order to conduct analyses to be used in evaluating potential options to reduce emissions from leaking equipment, a model plant approach was used. The following sections discuss the creation of these model plants.

Information related to equipment counts was obtained from a natural gas industry report. This document provided average equipment counts for gas production, gas processing, natural gas transmission and distribution. These average counts were used to develop model plants for wellheads, well pads, and gathering line and boosting stations in the production segment of the industry, for a natural gas processing plant, and for a compression/transmission station in the natural gas transmission segment. These equipment counts are consistent with those contained in EPA’s analysis to estimate methane emissions conducted in support of the Greenhouse Gas Mandatory Reporting Rule (subpart W), which was published in the *Federal Register* on November 30, 2010 (75 FR 74458), These model plants are discussed in the following sections.

8.2.2.1 Oil and Natural Gas Production

Oil and natural gas production varies from site-to site. Many production sites may include only a wellhead that is extracting oil or natural gas from the ground. Other production sites consist of wellheads attached to a well pad. A well pad is a site where the production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) associated with these operations. A well pad can serve one well on a pad or several wells on a pad. A wellhead site consisting of only the wellhead and affiliated piping is not considered to be a well pad. The number of wells feeding into a well pad can vary from one to as many as 7 wells. Therefore, the number of components with potential for equipment leaks can vary depending on the number of wells feeding into the production pad and the amount of processing equipment located at the site.

Table 8-1. Major Studies Reviewed for Consideration or Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factor (s)	Emissions Data	Control Options
Greenhouse Gas Mandatory Reporting Rule and Technical Supporting Documents	EPA	2010	Nationwide	X	X
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008[4]	EPA	2010	Nationwide	X	
Methane Emissions from the Natural Gas Industry[567]	Gas Research Institute / EPA	1996	Nationwide	X	X
Methane Emissions from the US Petroleum Industry (Draft) [8]	EPA	1996	Nationwide	X	
Methane Emissions from the US Petroleum Industry [9]	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States [10]	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories [11]	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State[12]	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements [13]	Environmental Defense Fund	2009	Regional	X	X
Emissions from oil and Natural Gas Production Facilities [14]	Texas Commission for Environmental Quality	2007	Regional	X	X
Petroleum and Natural Gas Statistical Data[15]	U.S. Energy Information Administration	2007-2009	Nationwide		
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations [16]	EPA	1999		X	X
Protocol for Equipment Leak Emission Estimates[17]	EPA	1995	Nationwide	X	X

In addition to wellheads and well pads, model plants were developed for gathering lines and boosting stations. The gathering lines and boosting stations are sites that collect oil and gas from well pads and direct them to the gas processing plants. These stations have similar equipment to well pads; however they are not directly connected to the wellheads.

The EPA/GRI report provided the average number of equipment located at a well pad and the average number of components for each of these pieces of equipment.[4]The type of production equipment located at a well pad include: gas wellheads, separators, meters/piping, gathering compressors, heaters, and dehydrators. The types of components that are associated with this equipment include: valves, connectors, open-ended lines, and pressure relief valves. Four model plants were developed for well pads and are presented in Table 8-2. These model plants were developed starting with one, three, five and seven wellheads, and adding the average numberof other pieces of equipment per wellhead. Gathering compressors are not included at well pads and were included in the equipment for gathering lines and boosting stations.

Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S and the Western U.S. for the EPA/GRI document. A summary of the component counts for oil and gas production well pads is presented in Table 8-3.

Gathering line and boosting station model plants were developed using the average equipment counts for oil and gas production. The average equipment count was assigned Model Plant 2 and Model Plants 1 and 3 were assumed to be equally distributed on either side of the average equipment count. Therefore, Model Plant 1 can be assumed to be a small gathering and boosting station, and Model Plant 3 can be assumed to be a large gathering and boosting station. A summary of the model plant production equipment counts for gathering lines and boosting stations is provided in Table 8-4.

Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S and the Western U.S. from the EPA/GRIdocument. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressors seals are addressed in a Chapter 6 of this document. A summary of the component counts for oil and gas gathering line and boosting stations are presented in Table 8-5.

Table 8-2.Average Equipment Count for Oil and Gas Production Well Pad Model Plants

Equipment	Model Plant 1	Model Plant 2	Model Plant 3
Gas Wellheads	1	5	48
Separators	---	4	40
Meter/Piping	---	2	24
In-Line Heaters	---	2	26
Dehydrators	---	2	19

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and Table 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-3.Average Component Count for Oil and Gas Production Well Pad Model Plants

Component	Model Plant 1	Model Plant 2	Model Plant 3	Model Plant 4
Valve	9	122	235	348
Connectors	37	450	863	1,276
Open-Ended Line	1	15	29	43
Pressure Relief Valve	0	5	10	15

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-4.Average Equipment Count for Oil and Gas Production Gathering Line and Boosting Station Model Plants

Equipment	Model Plant 1	Model Plant 2	Model Plant 3
Separators	7	11	15
Meter/Piping	4	7	10
Gathering Compressors	3	5	7
In-Line Heaters	4	7	10
Dehydrators	3	5	7

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and Table 4-7, June 1996. (EPA-600/R-96-080h)

Table 8-5. Average Component Count for Oil and Gas Production Gathering Line and Boosting Station Model Plants

Component	Model Plant 1	Model Plant 2	Model Plant 3
Valve	547	906	1,265
Connectors	1,723	2,864	4,005
Open-Ended Line	51	83	115
Pressure Relief Valve	29	48	67

DataSource: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8:Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

8.2.2.2 Oil and Natural Gas Processing

Natural gas processing involves the removal of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. The types of process equipment used to separate the liquids are separators, glycol dehydrators, and amine treaters. In addition, centrifugal and/or reciprocating compressors are used to pressurize and move the gas from the processing facility to the transmission stations.

New Source Performance Standards (NSPS) have already been promulgated for equipment leaks at new natural gas processing plants (40 CFR Part 60, subpart KKK), and were assumed to be the baseline emissions for this analysis. Only one model plant was developed for the processing sector. A summary of the model plant production components counts for an oil and gas processing facility is provided in Table 8-6.

8.2.2.3 Natural Gas Transmission/Storage

Natural gas transmission/storage stations are facilities that use compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, transmission stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment. This source category also does not include emissions from gathering lines and boosting stations. Component counts were obtained from the EPA/GRI report and are presented in Table 8-7.

8.3 Nationwide Emissions from New Sources

8.3.1 Overview of Approach

Nationwide emissions were calculated by using the model plant approach for estimating emissions. Baseline model plant emissions for the natural gas production, processing, and transmission sectors were calculated using the component counts and the component gas service emission factors.[5] Annual emissions were calculated assuming 8,760 hours of operation each year. The emissions factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The emission factors for the production and processing sectors that were used to estimate the new source emissions are presented in Table 8-8. Emission factors for the transmission sector are presented in

Table 8-6.Average Component Count for Oil and Gas Processing Model Plant

Component	Gas Plant (non-compressor components)
Valve	1,392
Connectors	4,392
Open-Ended Line	134
Pressure Relief Valve	29

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-13, June 1996. (EPA-600/R-96-080h)

Table 8-7.Average Component Count for a Gas TransmissionFacility

Component	Processing Plant Component Count
Valve	704
Connection	3,068
Open-Ended Line	55
Pressure Relief Valve	14

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-16, June 1996. (EPA-600/R-96-080h)

Table 8-8 Oil and Gas Production and Processing Operations Average Emissions Factors

Component Type	Component Service	Emission Factor (kg/hr/source)
Valves	Gas	4.5E-03
Connectors	Gas	2.0E-04
Open-Ended Line	Gas	2.0E-03
Pressure Relief Valve	Gas	8.8E-03

Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

Table 8-9. Emissions for VOC, hazardous air pollutants (HAP), and methane were calculated using TOC weight fractions.[6] A summary of the baseline emissions for each of the sectors are presented in Table 8-10.

8.3.2 Activity Data

Data from oil and gas technical documents and inventories were used to estimate the number of new sources for each of the oil and gas sectors. Information from the Energy Information Administration (EIA) was used to estimate the number of new wells, well pads, and gathering and boosting stations. The number of processing plants and transmission/storage facilities was estimated using data from the Oil and Gas Journal, and the EPA Greenhouse Gas Inventory. A summary of the steps used to estimate the new sources for each of the oil and gas sectors is presented in the following sections.

8.3.2.1 Well Pads

The EIA provided a forecast of the number of new conventional and unconventional gas wells for the Year 2015 for both exploratory and developmental wells. The EIA projected 19,097 conventional and unconventional gas wells in 2015. The number of wells was converted to number of well pads by dividing the total number of wells by the average number of wells serving a well pad which is estimated to be 5. Therefore, the number of new well pads was estimated to be 3,820. The facilities were divided into the model plants assuming a normal distribution of facilities around the average model plant (Model Plant 2).

8.3.2.2 Gathering and Boosting

The number of new gathering and boosting stations was estimated using the current inventory of gathering compressors listed in the EPA Greenhouse Gas Inventory. The total number of gathering compressors was listed as 32,233 in the inventory. The GRI/EPA document does not include a separate list of compressor counts for gathering and boosting stations, but it does list the average number of compressors in the gas production section. It was assumed that this average of 4.5 compressors for gas production facilities is applicable to gathering and boosting stations. Therefore, using the inventory of 32,233 compressors and the average number of 4.5 compressors per facility, we estimated the number of gathering and boosting stations to be 7,163. To estimate the number of new gathering and boosting stations, we used the same increase of 3.84 percent used to estimate well pads to estimate the number of new gathering and boosting stations. This provided an estimate of 275 new gathering and boosting

Table 8-9 Oil and Gas Transmission/Storage Average Emissions Factors

Component Type	Component Service	Emission Factor (kg/hr/source)
Valves	Gas	5.5E-03
Connectors	Gas	9.3E-04
Open-Ended Line	Gas	7.1E-02
Pressure Relief Valve	Gas	3.98E-02

Data Source:EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-17, June 1996. (EPA-600/R-96-080h)

Table 8-10. Baseline Emissions for the Oil and Gas Production, Processing, and Transmission/Storage Model Plants

Oil and Gas Sector	Model Plant	TOC Emissions (Tons/yr)	Methane Emissions (Tons/yr)	VOC Emissions (Tons/yr)	HAP Emissions (Tons/yr)
Well Pads	1	0.482	0.335	0.0930	0.00351
	2	13.3	9.24	2.56	0.0967
	3	139	96.5	26.8	1.01
Gathering & Boosting	1	30.5	21.2	5.90	0.222
	2	50.6	35.2	9.76	0.368
	3	70.6	49.1	13.6	0.514
Processing	1	74.0	51.4	14.3	0.539
Transmission/Storage	1	108.1	98.1	2.71	0.0806

stations that would be affected sources under the proposed NSPS. The new gathering and boosting stations were assumed to be normally distributed around the average model plant (Model Plant 2).

8.3.2.3 Processing Facilities

The number of new processing facilities was estimated using gas processing data from the Oil and Gas Journal. The Oil and Gas Journal Construction Survey currently shows 6,303 million cubic feet of gas per day (MMcf/day) additional gas processing capacity in various stages of development. The OGJ Gas Processing Survey shows that there is 26.9 trillion cubic feet per year (tcf/year) in existing capacity, with a current throughput of 16.6 tcf/year or 62 percent utilization rate. If the utilization rate remains constant, the new construction would add approximately 1.4 tcf/year to the processing system. This would be an increase of 8.5 percent to the processing sector. The recent energy outlook published by the EIApredicts a 1.03 tcf/year increase in natural gas processing from 21.07 to22.104 tcf/year. This would be an annual increase of 5 percent over the next five years.

The EPA Greenhouse Gas Inventory estimates the number of existing processing facilities to be 577 plants operating in the U.S. Based on the projections provided in Oil and Gas Journal and EIA, it was assumed that the processing sector would increase by 5 percent annually. Therefore the number of new sources was estimated to be 29 new processing facilities in the U.S.

8.3.2.4 Transmission/Storage Facilities

The number of new transmission and storage facilities was estimated using the annual growth rate of 5 percent used for the processing sector and the estimated number of existing transmission and storage facilities in the EPA Greenhouse Inventory. The inventory estimates 1,748 transmission stations and 400 storage facilities for a total of 2,148. Therefore, the number of new transmission/storage facilities was estimated to be 107.

8.3.3 Emission Estimates

Nationwide emission estimates for the new sources for well pads, gathering and boosting, processing, and transmission/storage are summarized in Table 8-11. For well pads and gathering and boosting stations, the numbers of new facilities were assumed to be normally distributed across the range of model plants.

Table 8-11. Nationwide Baseline Emissions for New Sources

Oil and Gas Sector	Model Plant	Number of New Facilities	TOC Emissions (tons/yr)	Methane Emissions (tons/yr)	VOC Emissions (tons/yr)	HAP Emissions (tons/yr)
Well Pads	1	605	292	203	56.3	2.12
	2	2,610	34,687	24,116	6,682	252
	3	605	84,035	58,389	16,214	612
	Total	3,820	119,014	82,708	22,952	866
Gathering & Boosting	1	44	1,312	912	254	9.55
	2	187	9,513	6,618	1,835	69.2
	3	44	3,106	2,160	598	22.6
	Total	275	13,931	9,690	2,687	101
Processing	1	29	2,146	1,490	415	15.6
Transmission/Storage	1	107	11,567	10,497	290	8.62

8.4 Control Techniques

8.4.1 Potential Control Techniques

EPA has determined that leaking equipment, such as valves, pumps, and connectors, are a significant source of VOC and HAP emissions from oil and gas facilities. The following section describes the techniques used to reduce emissions from these sources.

The most effective control technique for equipment leaks is the implementation of a leak detection and repair program (LDAR). Emissions reductions from implementing an LDAR program can potentially reduce product losses, increase safety for workers and operators, decrease exposure of hazardous chemicals to the surrounding community, reduce emissions fees, and help facilities avoid enforcement actions. The elements of an effective LDAR program include:

- Identifying Components;
- Leak Definition;
- Monitoring Components;
- Repairing Components; and
- Recordkeeping.

The primary source of equipment leak emissions from oil and gas facilities are from valves and connectors, because these are the most prevalent components and can number in the thousands. The major cause of emissions from valves and connectors is a seal or gasket failure due to normal wear or improper maintenance. A leak is detected whenever the measured concentration exceeds the threshold standard (i.e., leak definition) for the applicable regulation. Leak definitions vary by regulation, component type, service (e.g., light liquid, heavy liquid, gas/vapor), and monitoring interval. Most NSPS regulations have a leak definition of 10,000 ppm, while many NESHAP regulations use a 500-ppm or 1,000-ppm leak definition. In addition, some regulations define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting or clouding from or around components), sound (such as hissing), and smell.

For many NSPS and NESHAP regulations with leak detection provisions, the primary method for monitoring to detect leaking components is EPA Reference Method 21 (40 CFR Part 60, Appendix A). Method 21 is a procedure used to detect VOC leaks from process equipment using toxic vapor analyzer (TVA) or organic vapor analyzer (OVA). In addition, other monitoring tools such as; infrared camera, soap solution, acoustic leak detection, and electronic screening device, can be used to monitor process components.

In optical gas imaging, a live video image is produced by illuminating the view area with laser light in the infrared frequency range. In this range, hydrocarbons absorb the infrared light and are revealed as a dark image or cloud on the camera. The passive infrared cameras scan an area to produce images of equipment leaks from a number of sources. Active infrared cameras point or aim an infrared beam at a potential source to indicate the presence of equipment leaks. The optical imaging camera is easy to use and very efficient in monitoring many components in a short amount of time. However, the optical imaging camera cannot quantify the amount or concentration of equipment leak. To quantify the leak, the user would need to measure the concentration of the leak using a TVA or OVA. In addition, the optical imaging camera has a high upfront capital cost of purchasing the camera.

Acoustic leak detectors measure the decibel readings of high frequency vibrations from the noise of leaking fluids from equipment leaks using a stethoscope-type device. The decibel reading, along with the type of fluid, density, system pressure, and component type can be correlated into leak rate by using algorithms developed by the instrument manufacturer. The acoustic detector does not decrease the monitoring time because components are measured separately, like the OVA or TVA monitoring. The accuracy of the measurements using the acoustic detector can also be questioned due to the number of variables used to determine the equipment leak emissions.

Monitoring intervals vary according to the applicable regulation, but are typically weekly, monthly, quarterly, and yearly. For connectors, the monitoring interval can be every 1, 2, 4, or 8 years. The monitoring interval depends on the component type and periodic leak rate for the component type. Also, many LDAR requirements specify weekly visual inspections of pumps, agitators, and compressors for indications of liquids leaking from the seals. For each component that is found to be leaking, the first attempt at repair is to be made no later than five calendar days after each leak is detected. First attempts at repair include, but are not limited to, the following best practices, where practicable and appropriate:

- Tightening of bonnet bolts;

- Replacement of bonnet bolts;
- Tightening of packing gland nuts; and
- Injection of lubricant into lubricated packing.

Once the component is repaired; it should be monitored daily over the next several days to ensure the leak has been successfully repaired. Another method that can be used to repair component is to replace the leaking component with "leakless" or other technologies.

The LDAR recordkeeping requirement for each regulated process requires that a list of all ID numbers be maintained for all equipment subject to an equipment leak regulation. A list of components that are designated as "unsafe to monitor" should also be maintained with an explanation/review of conditions for the designation. Detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams should also be maintained with the results of performance testing and leak detection monitoring, which may include leak monitoring results per the leak frequency, monitoring leakless equipment, and non-periodic event monitoring.

Other factors that can improve the efficiency of an LDAR program that are not addressed by the standards include training programs for equipment monitoring personnel and tracking systems that address the cost efficiency of alternative equipment (e.g., competing brands of valves in a specific application).

The first LDAR option is the implementation of a subpart VVa LDAR program. This program is similar to the VV monitoring, but finds more leaks due to the lower leak definition, thereby achieving better emission reductions. The VVa LDAR program requires the annual monitoring of connectors using an OVA or TVA (10,000 ppm leak definition), monthly monitoring of valves (500 ppm leak definition) and requires open-ended lines and pressure relief devices to operate with no detectable emissions (500 ppm leak definition). The monitoring of each of the equipment types were also analyzed as a possible option for reducing equipment leak emissions. The second option involves using the monitoring requirements in subpart VVa for each type of equipment which include: valves; connectors; pressure relief devices; and open-ended lines for each of the oil and gas sectors.

The thirdoption that was investigated was the implementation of a LDAR program using an optical gas imaging system. This option is currently available as an alternative work practice (40 CFR Part 60, subpart A) for monitoring emissions from equipment leaks in subpart VVa. The alternative work practice requires monthly monitoring of all components using the optical gas imaging system and an annual monitoring of all components using a Method 21 monitoring device. The Method 21 monitoring allows the facility to quantify emissions from equipment leaks, since the optical gas imaging system can only provide the magnitude of the equipment leaks.

A fourth option that was investigated is a modification of the 40 CFR Part 60, subpart Aalternative work practice. The alternative work practice was modified by removing the required annual monitoring using a Method 21 instrument. This option only requires the monthly monitoring of components using the optical gas imaging system.

8.4.2 Subpart VVa LDAR Program

8.4.2.1 Description

The subpart VVa LDAR requires the monitoring of pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines, valves, and connectors. These components are monitored with an OVA or TVA to determine if a component is leaking and measure the concentration of the organics if the component is leaking. Connectors, valves, and pressure relief devices have a leak definition of 500 parts per million by volume (ppmv). Valves are monitored monthly, connectors are monitored annually, and open-ended lines and pressure relief valves have no monitoring requirements, but are required to operate without any detectable emissions. Compressors are not included in this LDAR option and are regulated separately.

8.4.2.2 Effectiveness

The control effectiveness of the LDAR program is based on the frequency of monitoring, leak definition, frequency of leaks, percentage of leaks that are repaired, and the percentage of reoccurring leaks. A summary of the chemical manufacturing and petroleum refinery control effectiveness for each of the components is shown in Table 8-12. As shown in the table the control effectiveness for all of the components varies from 45 to 96 percent and is dependent on the frequency of monitoring and the leak definition. Descriptions of the frequency of monitoring and leak definition are described further below.

> Monitoring Frequency: The monitoring frequency is the number of times each component is checked for leaks. For an example, quarterly monitoring requires that each component be checked for leaks 4 times per year, and annual monitoring requires that each component be checked for leaks once per year. As shown in Table 8-12, monthly monitoring provides higher control effectiveness than quarterly

Table 8-12. Control Effectiveness for an LDAR program at a Chemical Process Unit and a Petroleum Refinery

Equipment Type and Service	Control Effectiveness (% Reduction)		
	Monthly Monitoring 10,000 ppmv Leak Definition	Quarterly Monitoring 10,000 ppmv Leak Definition	500 ppm Leak Definition[a]
Chemical Process Unit			
Valves – Gas Service[b]	87	67	92
Valves – Light Liquid Service[c]	84	61	88
Pumps – Light Liquid Service[c]	69	45	75
Connectors – All Services	---	---	93
Petroleum Refinery			
Valves – Gas Service[b]	88	70	96
Valves – Light Liquid Service[c]	76	61	95
Pumps – Light Liquid Service[c]	68	45	88
Connectors – All Services	---	---	81

Source: Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017, Nov 1995.

a. Control effectiveness attributable to the HON-negotiated equipment leak regulation (40 CFR 63, Subpart H) is estimated based on equipment-specific leak definitions and performance levels. However, pumps subject to the HON at existing process units have a 1,000 to 5,000 ppm leak definition, depending on the type of process.
b. Gas (vapor) service means the material in contact with the equipment component is in a gaseous state at the process operating conditions.
c. Light liquid service means the material in contact with the equipment component is in a liquid state in which the sum of the concentration of individual constituents with a vapor pressure above 0.3 kilopascals (kPa) at 20°C is greater than or equal to 20% by weight.

monitoring. This is because leaking components are found and repaired more quickly, which lowers the amount of emissions that are leaked to the atmosphere.

> <u>Leak Definition:</u> The leak definition describes the local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound. Decreasing the leak definition concentration generally increases the number of leaks found during a monitoring period, which generally increases the number of leaks that are repaired.

The control effectiveness for the well pad, gathering and boosting stations, processing facilities, and transmissions and storage facilities were calculated using the LDAR control effectiveness and leak fraction equations for oil and gas production operation units in the EPA equipment leaks protocol document. The leak fraction equation uses the average leak rate (e.g., the component emission factor) and leak definition to calculate the leak fraction.[7] This leak fraction is used in a steady state set of equations to determine the final leak rate after implementing a LDAR program.[8] The initial leak rate and the final leak rate after implementing a LDAR program were then used to calculate the control effectiveness of the program. The control effectiveness for implementing a subpart VVa LDAR program was calculated to be 93.6 perccent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.2.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Subpart VVa monitoring frequency and leak definition were used for processing plants since they are already required to do subpart VV requirements. Connectors were assumed to be monitored over a 4-year period after initial annual compliance monitoring.
- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Subsequent monitoring costs are $1.50 for valves and connectors, $2.00 for pressure relief valve disks, and $5.00 for pressure relief valve devices and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

It was assumed that a single Method 21 monitoring device could be used at multiple locations for production pads, gathering and boosting stations, and transmission and storage facilities. To calculate the shared cost of the Method 21 device, the time required to monitor a single facility was estimated. For production pads and gathering and boosting stations, it was assumed that it takes approximately 1 minute to monitor a single component, and approximately 451 components would have to be monitored at an average facility in a month. This calculates to be 451 minutes or 7.5 hours per day. Assuming 20 working days in a typical month, a single Method 21 device could monitor 20 facilities. Therefore, the capital cost of the Method 21 device ($6,500) was divided by 20 to get a shared capital cost of $325 per facility. It was assumed for processing facilities that the full cost of the Method 21 monitoring device would apply to each individual plant. The transmission and storage segment Method 21 device cost was estimated using assuming the same 1 minute per component monitoring time. The average number of components that would need to be monitored in a month was estimated to be 1,440, which calculates to be 24 hours of monitoring time or 3 days. Assuming the same 20 day work month, the total number of facilities that could be monitored by a single Method 21 device is 7. Therefore, the shared cost of the Method 21 monitoring device was calculated to be $929 per site.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectors are provided in Table 8-13. In addition to the full subpart VVa LDAR monitoring, a component by component LDAR analysis was performed for each of the oil and gas sectors using the component count for an average size facility. This Model Plant 2 for well pads, Model Plant 2 for gathering and boosting stations, and Model Plant 1 for processing plants and transmission and storage facilities.

Table 8-13. Summary of the Model Plant Cost Effectiveness for the Subpart VVa Option

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	0.0876	0.00330	0.315	$15,418	$23,423	$23,350	$267,386	$7,088,667	$74,253
2	2.43	0.0915	8.73	$69,179	$37,711	$35,687	$15,549	$412,226	$4,318
3	25.3	0.956	91.3	$584,763	$175,753	$154,595	$6,934	$183,835	$1,926
Gathering and Boosting Stations									
1	5.58	0.210	20.1	$148,885	$57,575	$52,921	$10,327	$273,769	$2,868
2	9.23	0.348	33.2	$255,344	$84,966	$77,259	$9,203	$243,987	$2,556
3	12.9	0.486	46.4	$321,203	$105,350	$94,591	$8,174	$216,692	$2,270
Processing Plants									
1	13.5	0.508	48.5	$7,522	$45,160	$33,915	$3,352	$88,870	$931
Transmission/Storage Facilities									
1	2.62	0.0780	94.9	$94,482	$51,875	N/A	$19,769	$665,155	$546

Note: Transmission and storage facilities do not own the natural gas; therefore they do not receive any cost benefits from reducing the amount of natural gas as the result of equipment leaks.

The component costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Subsequent monitoring costs are $1.50 for valves and connectors, $2.00 for pressure relief valve disks, and $5.00 for pressure relief valve devices and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.
- Administrative costs and initial planning and training costs are were included for the component option and are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost for purchasing a TVA or OVA monitoring system was estimated to be $6,500.

The component control effectiveness for the subpart VVa component option were 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices. These were the same control effectiveness's that were used for the subpart VVa facility option. The control effectiveness for the modified subpart VVa option with less frequent monitoring was estimated assuming the control effectiveness follows a hyperbolic curve or a 1/x relationship with the monitoring frequency. Using this assumption the component cost effectiveness's were determined to be 87.2 percent for valves, 81.0 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices. The assumption is believed to provide a conservative estimate of the control efficiency based on less frequent monitoring. A summary of the capital and annual costs and the cost effectiveness for each of the components for each of the oil and gas sectors are provided in Tables 8-14, 8-15, 8-16, and 8-17.

8.4.2.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

Table 8-14. Summary of Component Cost Effectiveness for Well Pads for the Subpart VVa Options

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Subpart VVa Option										
Valves	235	12	1.84	0.0696	6.64	$11,175	$27,786	$15,063	$399,331	$4,183
Connectors	863	1/0.25[a]	0.308	0.0116	1.11	$7,830	$22,915	$74,283	$1,969,328	$20,628
PRD	10	0	0.164	0.00619	0.591	$48,800	$29,609	$180,537	$4,786,215	$50,135
OEL	29	0	0.108	0.00408	0.389	$9,458	$22,915	$211,992	$5,620,108	$58,870
Modified Subpart VVa– Less Frequent Monitoring										
Valves	235	1	1.31	0.0496	4.73	$11,175	$23,436	$17,828	$472,640	$4,951
Connectors	863	1/0.125[b]	0.261	0.00983	0.938	$7,830	$22,740	$87,277	$2,313,795	$24,237
PRD	5	0	0.164	0.00619	0.591	$48,800	$29,609	$180,537	$4,786,215	$50,135
OEL	29	0	0.108	0.00408	0.389	$9,458	$22,915	$211,992	$5,620,108	$58,870

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

Table 8-15. Summary of Component Cost Effectiveness for Gathering and Boosting Stations for the Subpart VVa Options

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Subpart VVa Option										
Valves	906	12	7.11	0.268	25.6	$24,524	$43,234	$6,079	$161,162	$1,688
Connectors	2,864	1/0.25[a]	1.02	0.0386	3.69	$10,914	$24,164	$23,603	$625,752	$6,555
PRD	48	0	0.787	0.0297	2.83	$195,140	$57,091	$72,523	$1,922,648	$20,139
OEL	83	0	0.309	0.0117	1.11	$14,966	$23,917	$77,310	$2,049,557	$21,469
Modified Subpart VVa – Less Frequent Monitoring										
Valves	906	1	5.07	0.191	18.2	$24,524	$24,461	$5,221	$138,417	$1,450
Connectors	2,864	1/0.125[b]	0.865	0.0326	3.11	$10,914	$23,584	$27,274	$723,067	$7,574
PRD	48	0	0.787	0.0297	2.83	$195,140	$57,091	$72,523	$1,922,648	$20,139
OEL	83	0	0.309	0.0117	1.11	$14,966	$23,917	$77,310	$2,049,557	$21,469

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

Table 8-16. Summary of Incremental Component Cost Effectiveness for Processing Plants for the Subpart VVa Option

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Incremental Component Cost for Subpart VV to Subpart VVa Option										
Valves	1,392	12	10.9	0.412	39.3	$6,680	$1,576	$144	$3,824	$40
Connectors	4,392	1/0.25[a]	1.57	0.0592	5.65	$2,559	$6,845	$4,360	$115,585	$1,211
PRD	29	0	0.499	0.0188	1.80	$0	$0	$0	$0	$0
OEL	134	0	0.476	0.0179	1.71	$0	$0	$0	$0	$0

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.

Table 8-17. Summary of Component Cost Effectiveness for Transmission and Storage Facilities for the Subpart VVa Options

Component	Average Number of Components	Monitoring Frequency (Times/yr)	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/yr)	Cost-effectiveness ($/ton)		
			VOC	HAP	Methane			VOC	HAP	Methane
Subpart VVa Option										
Valves	673	12	0.878	0.0261	31.8	$19,888	$37,870	$43,111	$1,450,510	$1,192
Connectors	3,068	1/0.25[a]	0.665	0.0198	24.1	$11,229	$24,291	$36,527	$1,229,005	$1,010
PRD	14	0	0.133	0.00397	4.83	$61,520	$32,501	$243,525	$8,193,684	$6,732
OEL	58	0	0.947	0.0282	34.3	$12,416	$23,453	$24,762	$833,137	$684
Modified Subpart VVa – Less Frequent Monitoring										
Valves	673	1	0.626	0.0186	22.6	$19,888	$25,410	$40,593	$1,365,801	$1,122
Connectors	3,068	1/0.125[b]	0.562	0.0167	20.3	$11,229	$23,669	$42,140	$1,417,844	$1,165
PRD	14	0	0.133	0.00397	4.83	$61,520	$32,501	$243,525	$8,193,684	$6,732
OEL	58	0	0.947	0.0282	34.3	$12,416	$23,453	$24,762	$833,137	$684

Minor discrepancies may be due to rounding.

a. It was assumed that all the connectors are monitored in the first year for initial compliance and every 4 years thereafter.
b. It was assumed that all the connectors are monitored in the first year for initial compliance and every 8 years thereafter.

8.4.3 LDAR with Optical Gas Imaging

8.4.3.1 Description

The alternative work practice for equipment leaks in §60.18 of 40 CFR Part 60, subpart A allows the use of an optical gas imaging system to monitor leaks from components. This LDAR requires monthly monitoring and repair of components using an optical gas imaging system, and annual monitoring of components using a Method 21 instrument. This requirement does not have a leak definition because the optical gas imaging system can only measure the magnitude of a leak and not the concentration. However, this alternative work practice does not require the repair of leaks below 500 ppm. Compressors are not included in this LDAR option and arediscussed in Chapter 6 of this document.

8.4.3.2 Effectiveness

No data was found on the control effectiveness of the alternative work practice. It is believed that this option would provide the same control effectiveness as the subpart VVa monitoring program. Therefore, the control effectiveness's for implementing an alternative work practice was assumed to be 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.3.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Monthly optical gas imaging monitoring costs are estimated to be $0.50 for valves, connectors, pressure relief valve devices, and open-ended lines.
- Annual monitoring costs using a Method 21 device are estimated to be $1.50 for valves and connectors, $2.00 for pressure relief valve disks, and $5.00 for pressure relief devices and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

It was assumed that a single optical gas imaging and a Method 21 monitoring device could be used at multiple locations for production pads, gathering and boosting stations, and transmission and storage facilities. To calculate the shared cost of the optical gas imaging system and the Method 21 device, the time required to monitor a single facility was estimated. For production pads and gathering and boosting stations, it was assumed that 8 production pads could be monitored per day. This means that 160 production facilities could be monitored in a month. In addition, it was assumed 13 gathering and boosting station would service these wells and could be monitored during the same month for a total of 173 facilities. Therefore, the capital cost of the optical gas imaging system (Flir Model GF320, $85,000) and the Method 21 device ($6,500) was divided by 173 to get a shared capital cost of $529 per facility. It was assumed for processing facilities that the full cost of the optical gas imaging system and the Method 21 monitoring device would apply to each individual plant. The transmission and storage segment Method 21 device cost was estimated assuming that one facility could be monitored in one hour, and the travel time between facilities was one hour. Therefore, in a typical day 4 transmission stations could be monitored in one day. Assuming the same 20 day work month, the total number of facilities that could be monitored by a single optical gas imaging system and Method 21 device is 80. Therefore, the shared cost of the Method 21 monitoring device was calculated to be $1,144 per site.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectorusing the alternative work practice monitoring is provided in Table 8-18. A component cost effectiveness analysis for the alternative work practice was not performed, because the optical gas imaging system is not conducive to component monitoring, but is intended for facility-wide monitoring.

8.4.3.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of

Table 8-18. Summary of the Model Plant Cost Effectiveness for the Optical Gas Imaging and Method 21 Monitoring Option

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	0.0876	0.00330	0.315	$15,428	$21,464	$21,391	$245,024	$6,495,835	$68,043
2	2.43	0.0915	8.73	$64,858	$39,112	$37,088	$16,127	$427,540	$4,478
3	25.3	0.956	91.3	$132,891	$135,964	$114,807	$5,364	$142,216	$1,490
Gathering and Boosting Stations									
1	5.58	0.210	20.1	$149,089	$63,949	$59,295	$11,470	$304,078	$3,185
2	9.23	0.348	33.2	$240,529	$93,210	$85,503	$10,096	$267,659	$2,804
3	12.9	0.486	46.4	$329,725	$121,820	$111,060	$9,451	$250,567	$2,625
Processing Plants									
1	13.5	0.508	48.5	$92,522	$87,059	$75,813	$6,462	$171,321	$1,795
Transmission/Storage Facilities									
1	2.62	0.0780	94.9	$20,898	$51,753	N/A	$19,723	$663,591	$545

Minor discrepancies may be due to rounding.

Note: Transmission and storage facilities do not own the natural gas; therefore cost benefits from reducing the amount of natural gas as the result of equipment leaks was not estimated for the transmission segment..

equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

8.4.4 Modified Alternative Work Practice with Optical Gas Imaging

8.4.4.1 Description

The modified alternative work practice for equipment leaks in §60.18 of 40 CFR Part 60, subpart A allows the use of an optical gas imaging system to monitor leaks from components, but removes the requirement of the annual Method 21 device monitoring. Therefore, the modified work practice would require only monthly monitoring and repair of components using an optical gas imaging system. This requirement does not have a leak definition because the optical gas imaging system can only measure the magnitude of a leak and not the concentration. However, this alternative work practice does not require the repair of leaks below 500 ppm. Compressors are not included in this LDAR option and are regulated separately.

8.4.4.2 Effectiveness

No data was found on the control effectiveness of this modified alternative work practice. However, it is believed that this option would provide the similar control effectiveness and emission reductions as the subpart VVa monitoring program. Therefore, the control effectiveness's for implementing an alternative work practice was assumed to be 93.6 percent for valves, 95.9 percent for connectors, 100 percent for open-ended lines, and 100 percent for pressure relief devices.

8.4.4.3 Cost Impacts

Costs were calculated using a LDAR cost spreadsheet developedfor estimating capital and annual costs for applying LDAR to the Petroleum Refinery and Chemical Manufacturing industry. The costs are based on the following assumptions:

- Initial monitoring and setup costs are $17.70 for valves, $1.13 per connector, $78.00 for pressure relief valve disks, $3,852 for pressure relief valve disk holder and valves, and $102 for open-ended lines.
- Monthly optical gas imaging monitoring costs are estimated to be $0.50 for valves, connectors, pressure relief valve devices, and open-ended lines.
- A wage rate of $30.46 per hour was used to determine labor costs for repair.

- Administrative costs and initial planning and training costs are based on the Miscellaneous Organic NESHAP (MON) analysis. The costs were based on 340 hours for planning and training and 300 hours per year for reporting and administrative tasks at $48.04 per hour.
- The shared capital cost for optical gas imaging system is $491 for production and gathering and boosting, $85,000 for processing, and $1,063 for transmission for a FLIR Model GF320 optical gas imaging system.
- The capital cost also includes $14,500 for a data collection system for maintaining the inventory and monitoring records for the components at a facility.
- Recovery credits were calculated assuming the methane reduction has a value of $4.00 per 1000 standard cubic feet.

A summary of the capital and annual costs and the cost effectiveness for each of the model plants in the oil and gas sectors using the alternative work practice monitoring is provided in Table 8-19. A component cost effectiveness analysis for the alternative work practice was not performed, because the optical gas imaging system is not conducive to component monitoring, but is intended for facility-wide monitoring.

8.4.4.4 Secondary Impacts

The implementation of a LDAR program reduces pollutant emissions from equipment leaks. No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of equipment leaks. Therefore, there are no secondary impacts expected from the implementation of a LDAR program.

8.5 Regulatory Options

The LDAR pollution prevention approach is believed to be the best method for reducing pollutant emissions from equipment leaks. Therefore, the following regulatory options were considered for reducing equipment leaks from well pads, gathering and boosting stations, processing facilities, and transmission and storage facilities:

- Regulatory Option 1: Require the implementation of a subpart VVa LDAR program;
- Regulatory Option 2: Require the implementation of a component subpart VVa LDAR program;
- Regulatory Option 3: Require the implementation of the alternative work practice in §60.18 of 40 CFR Part 60;

Table 8-19. Summary of the Model Plant Cost Effectiveness for Monthly Gas Imaging Monitoring

Model Plant	Annual Emission Reductions (tons/year)			Capital Cost ($)	Annual Cost ($/year)		Cost Effectiveness ($/ton)		
	VOC	HAP	Methane		without savings	with savings	VOC	HAP	Methane
Well Pads									
1	N/A	N/A	N/A	$15,390	$21,373	N/A	N/A	N/A	N/A
2	N/A	N/A	N/A	$64,820	$37,049	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	$537,313	$189,174	N/A	N/A	N/A	N/A
Gathering and Boosting Stations									
1	N/A	N/A	N/A	$149,051	$59,790	N/A	N/A	N/A	N/A
2	N/A	N/A	N/A	$240,491	$86,135	N/A	N/A	N/A	N/A
3	N/A	N/A	N/A	$329,687	$11,940	N/A	N/A	N/A	N/A
Processing Plants									
1	N/A	N/A	N/A	$92,522	$76,581	N/A	N/A	N/A	N/A
Transmission/Storage Facilities									
1	N/A	N/A	N/A	$20,817	$45,080	N/A	N/A	N/A	N/A

Note: This option only provides the number and magnitude of the leaks. Therefore, the emission reduction from this program cannot be quantified and the cost effectiveness values calculated.

- Regulatory Option 4: Require the implementation of a modified alternative work practice in §60.18 of 40 CFR Part 60 that removes the requirement for annual monitoring using a Method 21 device.

The following sections discuss these regulatory options.

8.5.1 Evaluation of Regulatory Options for Equipment Leaks

8.5.1.1 Well pads

The first regulatory option of a subpart VVa LDAR program was evaluated for well pads, which include the wells, processing equipment (separators, dehydrators, acid gas removal), as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. For well pads the VOC cost effectiveness for the model plants ranged from $267,386 per ton of VOC for a single well head facility to $6,934 ton of VOC for a well pad servicing 48 wells. Because of the high VOC cost effectiveness, Regulatory Option 1 was rejected for well pads.

The second regulatory option that was evaluated for well pads was Regulatory Option 2, which would require the implementation of a component subpart VVa LDAR program. The VOC cost effectiveness of this option ranged from $15,063 for valves to $211,992 for open-ended lines. These costs were determined to be unreasonable and therefore this regulatory option was rejected.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option ranged from $5,364 per ton of VOC for Model Plant 3to $245,024 per ton of VOC for Model Plant 1. This regulatory option was determined to be not cost effective and was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.2 Gathering and Boosting Stations

The first regulatory option was evaluated for gathering and boosting stations which include the processing equipment (separators, dehydrators, acid gas removal), as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. The VOC cost effectiveness for the gathering and boosting model plants ranged from $10,327 per ton of VOC for

Model Plant 1 to $8,174per ton of VOC for Model Plant 3. Regulatory Option 1 was rejected due to the high VOC cost effectiveness.

The second regulatory option that was evaluated for gathering and boosting stations was Regulatory Option 2. The VOC cost effectiveness of this option ranged from $6,079 for valves to $77,310 per ton of VOC for open-ended lines. These costs were determined to be unreasonable and therefore this regulatory option was also rejected.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option was calculated to be $10,724 per ton of VOC for Model Plant 1 and $8,685 per ton of VOC for Model Plant 3. This regulatory option was determined to be not cost effective and was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.3 Processing Plants

The VOC cost effectiveness of the first regulatory option was calculated to be $3,352 per ton of VOC. This cost effectiveness was determined to be reasonable and therefore this regulatory option was accepted.

The second option was evaluated for processing plants and the VOC cost effectiveness ranged from $0 for open-ended lined and pressure relief devices to $4,360 for connectors. Because the emission benefits and the cost effectiveness of Regulatory Option 1 were accepted, this option was not accepted.

The third regulatory option requires the implementation of a monthly LDAR program using an Optical gas imaging system with annual monitoring using a Method 21 device. The VOC cost effectiveness of this option was calculated to be $6,462 per ton of VOC and was determined to be not cost effective. Therefore, this regulatory option was rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.1.4 Transmission and Storage Facilities

The first regulatory option was evaluated for transmission and storage facilities which include separators and dehydrators, as well as any heaters and piping. The equipment does not include any of the compressors which will be regulated separately. This sector moves processed gas from the processing facilities to the city gates. The VOC cost effectiveness for Regulatory Option 1 was $19,769per ton of VOC. The high VOC cost effectiveness is due to the inherent low VOC concentration in the processed natural gas, therefore the VOC reductions from this sector are low in comparison to the other sectors. Regulatory Option 1 was rejected due to the high VOC cost effectiveness.

The second option was evaluated for transmission facilities and the VOC cost effectiveness ranged from $24,762 for open-ended lined to $243,525 for connectors. This option was not accepted because of the high cost effectiveness.

The third regulatory option that was evaluated for transmission and storage facilities was Regulatory Option 3. The VOC cost effectiveness of this option was calculated to be $19,723 per ton of VOC. Again, because of the low VOC content of the processed gas, the regulatory option has a low VOC reduction. This cost was determined to be unreasonable and therefore this regulatory option was also rejected.

The fourth regulatory option would require the implementation of a monthly LDAR program using an optical imaging instrument. The emission reductions from this option could not be quantified; therefore this regulatory option was rejected.

8.5.2 Nationwide Impacts of Regulatory Options

Regulatory Option 1 was selected as an option for setting standards for equipment leaks at processing plants. This option would require the implementation of an LDAR program using the subpart VVa requirements. For production facilities, 29 facilities per year are expected to be affected sources by the NSPS regulation annually. Table 8-20 provides a summary of the expected emission reductions from the implementation of this option.

Table 8-20. Nationwide Emission and Cost Analysis of Regulatory Options

Category	Estimated Number of Sources subject to NSPS	Facility Capital Cost ($)	Nationwide Emission Reductions (tpy)			VOC Cost Effectiveness ($/ton)		Methane Cost Effectiveness ($/ton)		Total Nationwide Costs (million $/year)		
			VOC	Methane	HAP	without savings	with savings	without savings	with savings	Capital Cost	Annual without savings	Annual with savings
Regulatory Option 2 (Subpart VVa LDAR Program)												
Processing Plants	29	$7,522	392	1,407	14.7	$3,352	$2,517	$931	$699	0.218	1.31	0.984

8.6 References

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APPENDIX A

E&P TANKS ANALYSIS FOR STORAGE VESSELS

Tank ID	Sample Tank No. 1	Sample Tank No. 2	Sample Tank No. 3	Sample Tank No. 4	Sample Tank No. 5	Sample Tank No. 6	Sample Tank No. 7	Sample Tank No. 8
E&P Tank Number	**Tank No. 58**	**Tank No. 59**	**Tank No. 60**	**Tank No. 61**	**Tank No. 62**	**Tank No. 63**	**Tank No. 64**	**Tank No. 65**
Total Emissions (tpy)	289.778	230.196	129.419	129.853	201.547	738.511	294.500	142.371
VOC Emissions (tpy)	43.734	111.414	101.853	63.343	154.313	578.379	205.794	89.728
Methane Emissions (tpy)	0.197	56.006	10.064	50.910	8.343	47.831	26.305	24.276
HAP Emissions (tpy)	**4.236**	**13.100**	**5.050**	**2.730**	**3.500**	**37.840**	**4.480**	**2.680**
Benzene	*0.828*	*6.343*	*0.501*	*0.285*	*0.051*	*7.568*	*0.116*	*0.219*
Toluene	*1.194*	*3.539*	*0.648*	*0.243*	*0.067*	*5.950*	*0.085*	*0.301*
E-Benzene	*0.041*	*0.083*	*0.040*	*0.008*	*0.002*	*0.086*	*0.006*	*0.020*
Xylenes	*0.165*	*0.327*	*0.233*	*0.066*	*0.046*	*0.679*	*0.018*	*0.152*
n-C6	*2.008*	*2.809*	*3.623*	*2.132*	*3.333*	*23.553*	*4.252*	*1.989*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	66	66	13	64	28	95	29	44
Separator Temperature (F)	83	90	110	74	78	118	60	71
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	83	90	110	74	78	118	60	71
C10+ SG	0.848	0.865	0.879	0.866	0.864	0.862	0.841	0.849
C10+ MW	234	237	294	301	281	312	224	349
API Gravity	**40.0**	**40.0**	**40.0**	**40.0**	**42.0**	**42.0**	**44.0**	**44.0**
Production Rate (bbl/day)	500	500	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.00	4.10	4.80	3.90	4.20	8.10	5.70	7.00
GOR (scf/bbl)	25.96	30.32	12.30	19.58	19.68	68.74	32.46	16.92
Heating Value of Vapor (Btu/s	398.80	1689.70	2486.42	1567.19	2261.27	2529.29	2162.56	2003.83
LP Oil Component	mol %							
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	5.0200	0.2700	0.0000	0.0800	0.0400	0.0000	0.0100	0.0200
N2	0.0000	0.0100	0.0000	0.0200	0.3100	0.0200	0.0200	0.0100
C1	0.0100	2.2600	0.4700	2.6500	0.4000	2.2500	1.1300	1.2900
C2	0.0400	1.2000	0.4800	0.3900	0.6500	3.1100	1.4100	1.0300
C3	0.2000	1.3200	1.5800	0.9200	1.7500	4.1100	3.2900	2.3000
i-C4	0.2800	0.7100	0.6200	0.9800	0.9200	1.3300	0.4500	1.1200
n-C4	0.4800	1.0800	2.6100	1.4700	2.4500	3.8100	4.0200	3.2200
i-C5	0.7600	1.2000	1.8100	2.0500	2.3900	2.5400	0.7000	2.3600
n-C5	0.7400	1.1300	2.9300	2.1600	2.9500	3.5100	4.0700	2.9600
C6	1.5100	2.0000	3.8800	3.4500	2.7600	3.0900	0.9600	3.0600
C7	4.6600	6.7600	10.7300	7.9400	10.8800	8.0100	5.5900	9.5000
C8	6.6100	9.4200	12.5300	9.6900	11.6400	7.6800	5.5200	11.5900
C9	4.8700	6.5600	6.9400	6.5600	6.1800	4.4400	4.2700	6.3200
C10+	70.1100	49.2600	47.3100	56.3900	52.0200	47.6400	63.0500	47.7200
Benzene	0.5700	4.9100	0.5800	0.4300	0.0700	1.3400	0.1600	0.3600
Toluene	2.1400	7.7900	1.9900	1.1000	0.2700	2.6800	0.3700	1.4900
E-Benzene	0.1700	0.4600	0.2900	0.1000	0.0200	0.0900	0.0700	0.2600
Xylenes	0.7600	2.0500	1.9000	0.9000	0.5500	0.8000	0.2500	2.2900
n-C6	1.0700	1.6100	3.3500	2.7200	3.7500	3.5500	4.6600	3.1000
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 9	Sample Tank No. 10	Sample Tank No. 11	Sample Tank No. 12	Sample Tank No. 13	Sample Tank No. 14	Sample Tank No. 15
E&P Tank Number	**Tank No. 66**	**Tank No. 67**	**Tank No. 68**	**Tank No. 69**	**Tank No. 70**	**Tank No. 71**	**Tank No. 72**
Total Emissions (tpy)	357.688	134.789	314.446	505.131	306.443	256.029	1061.274
VOC Emissions (tpy)	243.348	79.118	224.158	437.555	252.987	204.571	987.647
Methane Emissions (tpy)	56.846	37.876	18.892	21.472	15.159	21.237	32.940
HAP Emissions (tpy)	**5.590**	**5.680**	**7.030**	**13.450**	**15.330**	**6.500**	**56.780**
Benzene	*0.244*	*1.308*	*0.242*	*0.119*	*1.048*	*0.464*	*5.791*
Toluene	*0.440*	*1.184*	*0.385*	*0.146*	*1.488*	*0.927*	*6.793*
E-Benzene	*0.039*	*0.029*	*0.043*	*0.019*	*0.062*	*0.051*	*0.303*
Xylenes	*0.208*	*0.488*	*0.167*	*0.162*	*0.734*	*0.590*	*4.255*
n-C6	*4.661*	*2.671*	*6.191*	*13.008*	*12.001*	*4.468*	*39.634*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	60	41	20	23	24	52	45
Separator Temperature (F)	60	72	68	85	114	108	140
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	72	68	85	114	108	140
C10+ SG	0.878	0.854	0.926	0.848	0.87	0.886	0.893
C10+ MW	270	270	290	275	274	269	277
API Gravity	**44.0**	**45.0**	**45.0**	**46.0**	**46.0**	**47.0**	**47.0**
Production Rate (bbl/day)	500	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.10	5.20	8.10	4.70	5.00	5.30	6.00
GOR (scf/bbl)	41.30	17.66	30.80	43.26	26.30	24.28	78.80
Heating Value of Vapor (Btu/s	2060.54	1812.87	2234.66	2651.81	2611.90	2491.55	3120.85
LP Oil Component							
H2S	0.0000	0.0000	0.0000	0.0500	0.0700	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0500	0.0400	0.3100	0.2400	0.1700	0.0000	0.0400
N2	0.0000	0.0100	0.0200	0.0100	0.0000	0.0000	0.0000
C1	2.3400	1.8400	0.6900	0.9400	0.6200	0.9700	1.2100
C2	1.5600	0.6100	0.9400	0.6600	0.5200	0.7700	0.7600
C3	3.8500	1.2700	2.7300	2.1500	1.6800	2.0200	2.9200
i-C4	1.3600	0.8900	1.7300	1.1100	0.9900	1.5500	4.1500
n-C4	3.9600	1.5600	3.9300	4.5400	3.1200	2.1400	3.0600
i-C5	3.1300	1.8000	3.8800	3.0600	2.4500	3.3400	3.9300
n-C5	4.0300	1.8800	4.1000	4.9800	3.4200	2.8800	3.0900
C6	3.6100	3.4300	5.1500	4.1100	4.4300	3.2600	4.9100
C7	7.7900	10.7400	12.0700	10.2100	8.8900	9.0800	13.0800
C8	13.7700	12.6900	18.2000	10.6800	18.5800	11.7900	14.6200
C9	4.8300	7.8700	8.8800	5.4300	8.7200	5.8500	7.6300
C10+	42.2300	43.0100	27.3600	45.2800	36.2600	49.3100	31.1400
Benzene	0.2400	1.5600	0.3000	0.0600	0.5300	0.3000	0.6900
Toluene	1.3400	3.8100	1.4700	0.2100	1.9700	1.6000	1.9400
E-Benzene	0.3200	0.2200	0.4400	0.0700	0.1900	0.2100	0.1900
Xylenes	1.9700	4.1900	1.9600	0.6700	2.5500	2.7300	2.9800
n-C6	3.6200	2.5800	5.8400	5.5400	4.8400	2.2000	3.6600
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 16	Sample Tank No. 17	Sample Tank No. 18	Sample Tank No. 19	Sample Tank No. 20	Sample Tank No. 21
E&P Tank Number	**Tank No. 73**	**Tank No. 74**	**Tank No. 75**	**Tank No. 76**	**Tank No. 77**	**Tank No. 78**
Total Emissions (tpy)	464.597	214.658	1331.488	3972.618	540.533	1228.897
VOC Emissions (tpy)	383.349	135.482	1146.617	2331.105	399.555	940.078
Methane Emissions (tpy)	18.132	32.283	31.967	755.826	38.624	105.184
HAP Emissions (tpy)	**10.980**	**7.530**	**77.780**	**82.380**	**7.580**	**13.230**
Benzene	*0.222*	*1.269*	*7.661*	*12.470*	*2.447*	*0.543*
Toluene	*0.208*	*0.708*	*3.775*	*23.584*	*1.643*	*0.466*
E-Benzene	*0.058*	*0.019*	*0.113*	*0.056*	*0.051*	*0.006*
Xylenes	*0.193*	*0.411*	*0.929*	*0.635*	*0.256*	*0.052*
n-C6	*10.296*	*5.124*	*65.304*	*45.632*	*3.186*	*12.160*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	40	31	50	700	20	98
Separator Temperature (F)	76	76	125	100	48	40
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	76	76	125	100	48	40
C10+ SG	0.885	0.839	0.842	0.878	0.877	0.929
C10+ MW	318	296	287	178	179	324
API Gravity	**47.0**	**49.0**	**49.0**	**50.0**	**50.0**	**51.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.60	5.00	8.90	7.40	9.40	11.20
GOR (scf/bbl)	41.32	24.48	106.60	491.90	56.44	128.16
Heating Value of Vapor (Btu/s	2421.27	2045.68	2822.40	1916.15	2275.04	2279.83
LP Oil Component						
H2S	0.0000	0.0000	1.2800	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0400	0.0800	0.0300	0.4200	0.0100	0.0100
N2	0.8400	0.0100	0.0000	0.0700	0.0100	0.0400
C1	0.7800	1.4000	1.2700	15.3300	1.1400	3.2200
C2	0.7500	0.9700	2.0800	8.9600	1.6000	2.9500
C3	3.5300	1.3500	4.5700	8.2100	4.0100	6.4800
i-C4	2.0700	1.0500	1.8900	2.3100	2.3400	2.2000
n-C4	6.8800	2.4200	6.4800	4.1900	4.7300	8.5300
i-C5	5.0000	2.7100	3.8800	2.4300	4.1700	4.6800
n-C5	7.4800	3.2900	7.0400	2.3500	2.9700	7.4700
C6	4.1000	4.6900	3.0500	3.1100	4.3800	5.7300
C7	11.3200	11.3500	6.8200	8.4700	8.8100	15.8300
C8	11.7900	12.4100	7.7800	8.8400	12.3800	12.6400
C9	6.1100	9.3100	7.2300	3.7100	5.4900	4.0800
C10+	32.0700	36.0900	37.9300	23.5600	32.1400	18.1600
Benzene	0.1400	1.4000	0.8300	0.8200	2.8900	0.3400
Toluene	0.3800	2.3200	1.0200	4.6700	6.4200	1.0200
E-Benzene	0.2700	0.1600	0.0700	0.0300	0.5700	0.0400
Xylenes	1.0300	4.0200	0.6500	0.3900	3.3000	0.4000
n-C6	5.4200	4.9700	6.1000	2.1300	2.6400	6.1800
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 22	Sample Tank No. 23	Sample Tank No. 24	Sample Tank No. 25	Sample Tank No. 26	Sample Tank No. 27
E&P Tank Number	**Tank No. 79**	**Tank No. 80**	**Tank No. 81**	**Tank No. 82**	**Tank No. 83**	**Tank No. 84**
Total Emissions (tpy)	362.298	790.092	557.188	5007.636	175.911	714.052
VOC Emissions (tpy)	175.304	665.349	483.599	3386.300	77.584	639.895
Methane Emissions (tpy)	109.676	24.115	10.288	842.206	54.660	18.553
HAP Emissions (tpy)	**7.150**	**28.770**	**14.580**	**101.610**	**4.770**	**30.190**
Benzene	*0.353*	*3.892*	*1.930*	*9.782*	*0.929*	*4.165*
Toluene	*0.102*	*6.465*	*1.651*	*12.547*	*0.909*	*2.542*
E-Benzene	*0.120*	*0.119*	*0.055*	*0.040*	*0.050*	*0.192*
Xylenes	*0.437*	*2.017*	*0.631*	*0.716*	*0.221*	*1.424*
n-C6	*6.133*	*16.273*	*10.317*	*78.528*	*2.665*	*21.871*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	115	30	15	770	39	38
Separator Temperature (F)	73	100	86	100	66	95
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	73	100	86	100	66	95
C10+ SG	0.873	0.901	0.878	0.858	0.854	0.823
C10+ MW	200	220	254	195	175	375
API Gravity	**54.0**	**54.0**	**54.0**	**55.0**	**57.0**	**57.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	5.30	9.40	10.30	7.80	5.70	9.60
GOR (scf/bbl)	51.34	68.32	47.12	578.20	25.46	57.38
Heating Value of Vapor (Btu/s	1678.80	2676.21	2764.90	2043.18	1632.00	2897.16
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0900	0.1100	0.0200	0.5500	0.0700	0.0400
N2	0.0300	0.0200	0.0100	0.0300	0.0000	0.0000
C1	3.5600	0.7100	0.3300	16.1500	1.7200	0.7000
C2	1.4300	1.5400	1.0900	7.1400	0.9000	1.0900
C3	1.8700	4.5900	3.8300	9.6600	1.3800	3.5600
i-C4	0.6800	2.3400	3.7000	3.8100	1.0000	2.9000
n-C4	2.0000	4.4400	4.8700	5.9600	1.4900	6.2100
i-C5	1.6600	3.9000	4.4800	3.5300	1.4600	6.0400
n-C5	2.0600	3.8000	3.9800	3.7200	1.5300	5.8400
C6	2.4100	5.0900	6.0500	3.8400	4.0600	7.3200
C7	15.0800	12.9700	15.6400	8.7600	14.5700	13.0000
C8	25.1900	19.0700	17.5800	8.9200	23.7200	12.2200
C9	12.4900	6.9500	6.1000	3.1000	13.7700	7.9600
C10+	24.3900	18.9200	21.1300	17.9300	20.9800	20.0200
Benzene	0.2400	1.2000	1.0500	0.5800	1.4900	1.2200
Toluene	0.2100	5.5400	2.6000	2.3000	4.5300	2.0500
E-Benzene	0.6600	0.2500	0.2200	0.0200	0.6700	0.3800
Xylenes	2.7600	4.8300	2.8900	0.4200	3.4200	3.2200
n-C6	3.1900	3.7300	4.4300	3.5800	3.2400	6.2300
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 28**	**Sample Tank No. 29**	**Sample Tank No. 30**	**Sample Tank No. 31**	**Sample Tank No. 32**	**Sample Tank No. 33**
E&P Tank Number	**Tank No. 85**	**Tank No. 86**	**Tank No. 87**	**Tank No. 88**	**Tank No. 89**	**Tank No. 90**
Total Emissions (tpy)	801.228	983.881	4326.573	3074.670	2951.879	616.490
VOC Emissions (tpy)	757.176	750.313	2406.579	1892.668	1439.584	332.126
Methane Emissions (tpy)	5.307	49.123	1088.727	746.499	999.175	120.918
HAP Emissions (tpy)	**29.510**	**14.080**	**58.180**	**47.230**	**44.040**	**9.140**
Benzene	*3.415*	*1.119*	*4.653*	*5.891*	*1.409*	*0.576*
Toluene	*5.329*	*1.453*	*5.785*	*6.575*	*2.934*	*1.658*
E-Benzene	*0.192*	*0.049*	*0.186*	*0.022*	*0.159*	*0.079*
Xylenes	*1.786*	*0.263*	*0.989*	*0.316*	*1.136*	*0.806*
n-C6	*18.788*	*11.194*	*46.561*	*34.427*	*38.406*	*6.016*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	65	54	870	600	780	60
Separator Temperature (F)	80	60	78	70	70	56
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	80	60	78	70	70	60
C10+ SG	0.899	0.868	0.868	0.847	0.905	0.905
C10+ MW	166	268	268	176	174	174
API Gravity	**57.0**	**57.0**	**57.0**	**57.0**	**58.0**	**58.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.80	13.10	13.10	7.50	8.00	8.00
GOR (scf/bbl)	61.26	97.00	578.20	396.24	436.98	79.54
Heating Value of Vapor (Btu/s	3046.83	2390.47	1789.23	1831.51	1633.60	1851.14
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	0.0800	0.4200	0.5800	0.2700	0.0800
N2	0.0000	0.0000	0.0800	0.0200	0.0200	0.0100
C1	0.1500	1.4800	21.2000	16.0200	20.3000	3.3900
C2	0.5700	2.9100	8.2900	4.1200	5.1800	2.4300
C3	2.4100	6.9600	8.5400	6.9000	5.6800	3.8400
i-C4	1.7300	2.6300	2.3000	2.7500	1.4200	1.3000
n-C4	3.5500	7.2100	5.8400	4.9100	4.1400	3.2000
i-C5	4.1400	4.6400	3.3500	3.6000	2.5400	2.4100
n-C5	3.8600	5.7100	4.0400	3.9000	3.1000	2.5600
C6	6.5100	5.0100	3.4200	3.9500	3.7700	3.7700
C7	18.7100	13.5500	9.1200	10.3800	11.2200	13.2600
C8	19.4300	15.0600	10.0900	11.3000	14.7500	22.4400
C9	6.8400	6.2300	4.1700	4.2100	7.0600	11.1300
C10+	15.5200	18.8400	12.5900	19.2800	13.5400	16.0600
Benzene	1.1800	0.5900	0.4000	0.8200	0.1800	0.4100
Toluene	5.2100	2.5000	1.6800	3.0600	1.2600	3.8600
E-Benzene	0.4600	0.2400	0.1600	0.0300	0.2000	0.5200
Xylenes	4.8600	1.4900	1.0000	0.5000	1.6700	6.1500
n-C6	4.8600	4.8700	3.3100	3.6700	3.7000	3.1800
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 34	Sample Tank No. 35	Sample Tank No. 36	Sample Tank No. 37	Sample Tank No. 38	Sample Tank No. 39
E&P Tank Number	**Tank No. 91**	**Tank No. 92**	**Tank No. 93**	**Tank No. 94**	**Tank No. 95**	**Tank No. 96**
Total Emissions (tpy)	2575.122	2774.089	653.459	3495.242	363.650	4744.399
VOC Emissions (tpy)	1494.749	2092.925	394.781	2876.860	223.772	3658.384
Methane Emissions (tpy)	581.208	346.071	121.446	169.818	84.912	381.967
HAP Emissions (tpy)	**65.980**	**48.710**	**14.210**	**93.030**	**10.760**	**89.970**
Benzene	*9.303*	*2.750*	*0.871*	*10.232*	*0.500*	*11.564*
Toluene	*14.114*	*2.311*	*2.688*	*11.558*	*0.279*	*11.735*
E-Benzene	*0.019*	*0.128*	*0.136*	*0.034*	*0.060*	*0.033*
Xylenes	*0.409*	*0.872*	*1.400*	*0.580*	*0.256*	*0.472*
n-C6	*42.130*	*42.650*	*9.111*	*70.629*	*9.661*	*66.162*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	500	300	110	750	85	730
Separator Temperature (F)	84	80	72	90	85	84
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	84	80	72	90	85	84
C10+ SG	0.909	0.882	0.901	0.898	0.9	0.898
C10+ MW	204	296	162	215	202	225
API Gravity	**58.0**	**58.0**	**59.0**	**60.0**	**61.0**	**61.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	9.10	10.60	10.00	9.40	7.00	9.80
GOR (scf/bbl)	323.88	287.10	79.90	320.48	45.04	475.20
Heating Value of Vapor (Btu/s	1892.64	2289.04	1946.32	2541.49	1921.87	2340.56
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.2300	0.0300	0.0800	0.3400	0.0400	0.4100
N2	0.0600	0.0900	0.0100	0.0200	0.0200	0.0300
C1	12.9800	8.4300	3.3900	3.7500	2.6100	7.3900
C2	5.7800	4.2300	2.4300	4.7700	1.1600	6.6400
C3	4.6400	5.9100	3.8400	9.2600	2.2100	10.9400
i-C4	2.0900	5.1700	1.3000	4.8100	0.9300	4.5800
n-C4	4.1800	6.2200	3.2000	7.0200	2.4900	8.3400
i-C5	4.9600	8.9100	2.4100	5.5900	2.1300	5.5000
n-C5	4.0700	4.9700	2.5600	6.1200	2.9200	5.8200
C6	6.0700	9.1100	3.7700	6.1300	3.5400	5.3200
C7	13.1100	11.3400	13.2600	12.8200	19.5300	11.2900
C8	11.9500	10.3900	22.4400	12.5200	27.1600	11.1800
C9	4.8600	5.9600	11.1300	4.0100	14.7000	3.1900
C10+	14.1100	11.7500	16.0600	11.4200	13.8800	8.8000
Benzene	1.1400	0.3700	0.4100	1.1000	0.2900	1.1400
Toluene	5.4100	0.9800	3.8600	3.7900	0.4700	3.7600
E-Benzene	0.0200	0.1500	0.5200	0.0300	0.2600	0.0300
Xylenes	0.5000	1.1900	6.1500	0.5900	1.2600	0.5000
n-C6	3.8400	4.8000	3.1800	5.9100	4.4000	5.1400
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 40	Sample Tank No. 41	Sample Tank No. 42	Sample Tank No. 43	Sample Tank No. 44	Sample Tank No. 45
E&P Tank Number	**Tank No. 97**	**Tank No. 98**	**Tank No. 99**	**Tank No. 100**	**Tank No. 101**	**Tank No. 102**
Total Emissions (tpy)	907.495	277.197	3410.034	2122.607	8152.118	6780.555
VOC Emissions (tpy)	734.651	158.333	2732.261	1066.705	5678.554	4276.160
Methane Emissions (tpy)	49.578	75.426	159.904	736.341	1206.981	1045.765
HAP Emissions (tpy)	**24.160**	**8.820**	**67.500**	**64.680**	**81.710**	**48.890**
Benzene	*1.573*	*0.204*	*9.290*	*9.500*	*10.844*	*5.934*
Toluene	*3.102*	*0.854*	*9.192*	*15.007*	*8.516*	*1.416*
E-Benzene	*0.094*	*0.042*	*0.016*	*0.161*	*0.012*	*0.222*
Xylenes	*1.079*	*0.375*	*0.371*	*1.585*	*0.288*	*1.359*
n-C6	*18.314*	*7.344*	*48.628*	*38.425*	*62.050*	*39.961*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	57	72	730	580	730	807
Separator Temperature (F)	82	80	80	77	80	96
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	82	80	80	77	80	96
C10+ SG	0.884	0.869	0.883	0.85	0.895	0.811
C10+ MW	240	190	226	190	197	173
API Gravity	**62.0**	**63.0**	**63.0**	**64.0**	**64.0**	**66.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	10.40	7.00	11.90	6.40	11.00	11.80
GOR (scf/bbl)	84.20	36.56	321.62	309.64	924.96	804.54
Heating Value of Vapor (Btu/s	2521.70	1805.12	2477.18	1622.20	2083.02	2013.21
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0800	0.0400	0.3200	0.0700	0.5600	0.2200
N2	0.0100	0.0300	0.0200	0.0700	0.0300	0.0800
C1	1.4000	2.3500	3.4800	16.3500	16.9100	16.2600
C2	1.7700	1.0000	5.5300	3.6400	8.6200	11.7100
C3	4.8200	2.0700	10.1700	3.5600	12.0400	11.6100
i-C4	2.8200	0.7100	4.9900	1.6900	5.2700	4.3900
n-C4	5.9700	2.2600	8.1400	2.9800	9.0700	7.5600
i-C5	4.3100	1.7000	5.8700	2.6800	5.6500	4.5200
n-C5	4.1900	2.7400	6.1600	2.7900	5.8200	3.9400
C6	6.5100	3.4900	5.7200	3.8200	5.1000	3.3600
C7	17.7500	17.7300	12.3800	18.1400	8.0600	5.9200
C8	18.6400	27.9100	12.3100	19.4700	7.5500	11.6900
C9	7.4400	16.1500	3.7900	4.5900	2.2200	5.9200
C10+	11.6100	12.2800	9.9100	6.7300	5.6700	8.9300
Benzene	0.5600	0.1600	1.2800	1.2200	0.8500	0.3700
Toluene	3.2800	1.9800	4.0500	6.0700	2.3800	0.3000
E-Benzene	0.2600	0.2500	0.0200	0.1800	0.0100	0.1400
Xylenes	3.4100	2.5800	0.5300	2.0600	0.2900	1.0100
n-C6	5.1700	4.5700	5.3300	3.8900	3.9000	2.0700
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 46	Sample Tank No. 47	Sample Tank No. 48	Sample Tank No. 49	Sample Tank No. 50	Sample Tank No. 51
E&P Tank Number	**Tank No. 103**	**Tank No. 1**	**Tank No. 2**	**Tank No. 3**	**Tank No. 4**	**Tank No. 5**
Total Emissions (tpy)	927.902	95.816	112.738	74.503	155.244	93.073
VOC Emissions (tpy)	623.038	6.175	61.936	28.446	61.470	51.471
Methane Emissions (tpy)	167.129	0.115	1.927	0.309	46.064	0.440
HAP Emissions (tpy)	**20.320**	**0.460**	**2.960**	**0.990**	**1.760**	**3.190**
Benzene	*1.625*	*0.006*	*0.076*	*0.012*	*0.010*	*0.218*
Toluene	*1.876*	*0.013*	*0.060*	*0.031*	*0.037*	*0.074*
E-Benzene	*0.062*	*0.007*	*0.019*	*0.002*	*0.025*	*0.006*
Xylenes	*0.696*	*0.018*	*0.105*	*0.041*	*0.069*	*0.048*
n-C6	*16.059*	*0.421*	*2.704*	*0.904*	*1.616*	*2.845*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	170	45	22	20	53	15
Separator Temperature (F)	75	106	155	160	101	120
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	75	106	155	160	101	120
C10+ SG	0.801	0.972	0.972	0.952	0.961	0.984
C10+ MW	196	425	436	458	394	551
API Gravity	**68.0**	**15.0**	**17.0**	**18.0**	**19.0**	**19.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	12.50	0.80	2.00	0.60	2.30	4.80
GOR (scf/bbl)	106.60	8.88	9.60	6.44	17.78	7.52
Heating Value of Vapor (Btu/s	2081.33	181.43	1738.61	1076.97	1365.68	1718.17
LP Oil Component						
H2S	0.0000	0.1100	0.0000	0.0400	0.5100	0.1400
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	2.8500	1.3000	1.5400	1.1900	1.5000
N2	0.0100	0.0000	0.0000	0.0300	0.0100	0.0000
C1	4.9300	0.0100	0.1500	0.0300	1.5300	0.0400
C2	2.5800	0.0100	0.4000	0.0400	0.5300	0.2400
C3	3.4200	0.0200	0.7800	0.2200	0.8100	0.8500
i-C4	3.4300	0.0500	0.5600	0.1600	0.5000	0.6500
n-C4	3.7300	0.1800	1.2600	0.4700	1.2000	1.6500
i-C5	5.5500	0.3200	0.8700	0.4300	1.1500	2.1900
n-C5	3.6500	0.4500	1.2400	0.6500	1.3400	3.1500
C6	8.0700	0.6000	1.9800	0.6100	1.7500	4.7300
C7	14.6500	1.7200	3.4500	1.5800	3.6200	6.2500
C8	13.2600	2.1800	4.2600	2.0700	3.5300	10.2800
C9	7.8000	1.8400	3.6600	2.2800	3.5300	5.9300
C10+	19.6300	88.7100	78.1500	88.9700	76.8100	57.9100
Benzene	0.5400	0.0100	0.0500	0.0100	0.0100	0.3000
Toluene	1.9200	0.0600	0.0900	0.0600	0.1000	0.2600
E-Benzene	0.1700	0.0800	0.0600	0.0100	0.1600	0.0500
Xylenes	2.2200	0.2300	0.3700	0.1800	0.5100	0.4300
n-C6	4.4300	0.5700	1.3700	0.6200	1.2100	3.4500
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 52	Sample Tank No. 53	Sample Tank No. 54	Sample Tank No. 55	Sample Tank No. 56	Sample Tank No. 57
E&P Tank Number	**Tank No. 6**	**Tank No. 7**	**Tank No. 8**	**Tank No. 9**	**Tank No. 10**	**Tank No. 11**
Total Emissions (tpy)	24.484	26.091	29.739	114.630	42.075	
VOC Emissions (tpy)	3.087	17.629	11.288	74.707	8.263	
Methane Emissions (tpy)	15.587	2.836	5.908	25.400	27.176	
HAP Emissions (tpy)	**0.190**	**0.510**	**0.330**	**2.120**	**0.090**	
Benzene	*0.003*	*0.007*	*0.013*	*0.039*	*0.028*	
Toluene	*0.006*	*0.014*	*0.008*	*0.071*	*0.010*	
E-Benzene	*0.000*	*0.001*	*0.003*	*0.007*	*0.000*	
Xylenes	*0.005*	*0.012*	*0.007*	*0.090*	*0.001*	
n-C6	*0.175*	*0.474*	*0.298*	*1.919*	*0.052*	
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	
Separator Pressure (psig)	23	17	18	54	35	
Separator Temperature (F)	79	106	75	125	76	
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	
Ambient Temperature (F)	79	106	75	125	76	
C10+ SG	0.947	0.967	0.963	0.943	0.923	
C10+ MW	368	383	401	363	278	
API Gravity	**20.0**	**20.0**	**20.0**	**21.0**	**23.0**	
Production Rate (bbl/day)	500	500	500	500	500	
Reid Vapor Pressure (psia)	1.20	3.30	3.80	1.10	1.80	
GOR (scf/bbl)	4.98	2.82	3.94	13.90	8.52	
Heating Value of Vapor (Btu/s	1067.32	2208.23	1236.41	1980.20	1192.63	
LP Oil Component						
H2S	0.0100	0.0000	0.0000	0.0000	0.0000	
O2	0.0000	0.0000	0.0000	0.0000	0.0000	
CO2	0.0700	0.0000	0.2500	0.0000	0.0600	
N2	0.0900	0.0000	0.2100	0.0100	0.0100	
C1	1.2500	0.1900	0.5300	1.8000	1.7700	
C2	0.2000	0.2300	0.3300	0.5400	0.2900	
C3	0.0800	0.7500	0.7500	0.5200	0.3700	
i-C4	0.0900	0.4900	0.4900	0.2800	0.2300	
n-C4	0.1800	1.5700	1.5000	0.9200	0.3100	
i-C5	0.4000	1.5300	1.3500	0.9800	0.4900	
n-C5	0.4500	1.9100	1.7700	0.9700	0.2400	
C6	1.0500	2.7500	2.3700	1.6800	0.2500	
C7	2.3300	3.9000	4.3000	3.0100	0.5900	
C8	2.9800	6.8100	5.5200	3.7300	0.5000	
C9	2.6000	4.0100	3.5700	3.5400	0.2500	
C10+	87.0300	73.0300	74.2800	80.2500	94.2100	
Benzene	0.0200	0.0400	0.1000	0.0300	0.1100	
Toluene	0.1100	0.2200	0.1900	0.1400	0.1200	
E-Benzene	0.0200	0.0500	0.1900	0.0300	0.0100	
Xylenes	0.2700	0.5100	0.4700	0.4500	0.0500	
n-C6	0.7700	2.0100	1.8300	1.1200	0.1400	
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	
	100.0000	100.0000	100.0000	100.0000	100.0000	0.0000

Tank ID	Sample Tank No. 58	Sample Tank No. 59	Sample Tank No. 60	Sample Tank No. 61	Sample Tank No. 62	Sample Tank No. 63
E&P Tank Number	**Tank No. 12**	**Tank No. 13**	**Tank No. 14**	**Tank No. 15**	**Tank No. 16**	**Tank No. 17**
Total Emissions (tpy)	134.719	26.214	195.573	142.068	191.224	35.095
VOC Emissions (tpy)	63.729	5.207	109.615	69.135	105.838	25.578
Methane Emissions (tpy)	16.689	12.924	7.759	5.438	4.313	3.029
HAP Emissions (tpy)	**1.170**	**0.430**	**2.810**	**1.760**	**2.110**	**0.750**
Benzene	*0.020*	*0.008*	*0.033*	*0.024*	*0.041*	*0.011*
Toluene	*0.014*	*0.032*	*0.032*	*0.053*	*0.079*	*0.022*
E-Benzene	*0.007*	*0.002*	*0.023*	*0.003*	*0.003*	*0.003*
Xylenes	*0.027*	*0.019*	*0.064*	*0.041*	*0.016*	*0.011*
n-C6	*1.104*	*0.371*	*2.659*	*1.640*	*1.969*	*0.701*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	30	20	20	22	20	19
Separator Temperature (F)	66	122	88	86	68	133
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	66	122	88	86	68	133
C10+ SG	0.946	0.926	0.945	0.944	0.964	0.928
C10+ MW	382	336	381	404	444	327
API Gravity	**23.0**	**24.0**	**24.0**	**24.0**	**24.0**	**25.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.00	0.60	3.90	4.60	4.80	4.10
GOR (scf/bbl)	15.42	4.60	19.12	13.74	17.84	3.48
Heating Value of Vapor (Btu/s	1553.86	1059.39	1747.39	1543.44	1703.42	2314.31
LP Oil Component						
H2S	0.4400	0.0000	0.5200	0.4500	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.6400	0.1200	0.9600	1.1500	1.4200	0.0500
N2	0.0100	0.1000	0.1200	0.0200	0.0200	0.0000
C1	1.0700	0.9400	0.4900	0.3600	0.2700	0.2500
C2	0.5400	0.0500	0.6500	0.5000	0.6200	0.4900
C3	1.4100	0.0700	1.7300	1.5900	1.9400	1.1600
i-C4	0.7000	0.0600	0.7400	0.7600	1.1000	0.6000
n-C4	1.9400	0.1000	2.4600	2.4000	3.0100	1.5900
i-C5	1.8900	0.2400	1.7900	1.7300	2.1900	1.4300
n-C5	2.3600	0.2300	2.3100	2.1400	3.2100	1.4400
C6	2.7100	0.9100	2.6100	2.6400	3.9300	1.9900
C7	5.1800	2.8000	5.3300	5.5200	5.6800	3.5100
C8	5.3700	4.2200	5.5400	6.0700	11.3000	4.4100
C9	3.9800	4.3400	4.2100	4.6000	6.7600	4.4400
C10+	68.6500	84.5400	67.0700	66.9000	54.5000	76.8100
Benzene	0.0500	0.0200	0.0400	0.0400	0.0800	0.0300
Toluene	0.1100	0.2100	0.1100	0.2600	0.4700	0.1500
E-Benzene	0.1500	0.0300	0.2000	0.0400	0.0400	0.0400
Xylenes	0.6500	0.3100	0.6300	0.5800	0.2900	0.1800
n-C6	2.1500	0.7100	2.4900	2.2500	3.1700	1.4300
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 64**	**Sample Tank No. 65**	**Sample Tank No. 66**	**Sample Tank No. 67**	**Sample Tank No. 68**	**Sample Tank No. 69**
E&P Tank Number	**Tank No. 18**	**Tank No. 19**	**Tank No. 20**	**Tank No. 21**	**Tank No. 22**	**Tank No. 23**
Total Emissions (tpy)	139.887	70.761	171.538	38.394	215.631	148.757
VOC Emissions (tpy)	89.426	46.290	110.120	12.834	164.956	138.780
Methane Emissions (tpy)	21.590	4.142	15.382	16.424	8.875	1.515
HAP Emissions (tpy)	**1.190**	**2.570**	**1.670**	**0.720**	**4.240**	**5.310**
Benzene	*0.011*	*0.371*	*0.013*	*0.224*	*0.985*	*1.086*
Toluene	*0.035*	*0.697*	*0.017*	*0.209*	*0.787*	*0.854*
E-Benzene	*0.010*	*0.039*	*0.004*	*0.007*	*0.020*	*0.025*
Xylenes	*0.025*	*0.176*	*0.025*	*0.066*	*0.118*	*0.122*
n-C6	*1.109*	*1.292*	*1.613*	*0.216*	*2.331*	*3.227*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	30	25	31	23	17	20
Separator Temperature (F)	60	136	64	79	86	120
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	136	64	79	86	120
C10+ SG	0.94	0.916	0.938	0.908	0.946	0.932
C10+ MW	380	431	340	324	323	326
API Gravity	**25.0**	**27.0**	**27.0**	**29.0**	**29.0**	**29.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.90	3.30	5.20	3.10	4.80	4.90
GOR (scf/bbl)	16.66	6.76	18.46	6.36	20.11	11.50
Heating Value of Vapor (Btu/s	1966.88	2041.97	1887.18	1405.21	2354.30	2985.81
LP Oil Component						
H2S	0.0000	0.3800	0.2400	0.0000	0.2700	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0600	0.2200	0.2100	0.0900	0.0800	0.0300
N2	0.0400	0.1000	0.3000	0.0000	0.0000	0.0000
C1	1.3500	0.3200	0.8600	1.1200	0.4400	0.0800
C2	0.8500	0.4100	0.5400	0.5300	0.7000	0.2000
C3	2.0900	1.0700	1.7500	0.7000	2.0600	1.3000
i-C4	1.1400	0.5700	1.1600	0.4500	0.9700	1.0400
n-C4	2.7100	1.4500	3.1500	0.6300	2.7500	3.8800
i-C5	2.1900	1.5700	2.9100	0.6400	2.7000	2.2100
n-C5	2.4600	1.5100	2.5900	0.4600	2.3200	3.2000
C6	2.2400	2.5400	3.7200	0.8400	3.5000	2.5500
C7	5.7900	3.5300	5.8600	4.7900	8.3100	7.2000
C8	4.7900	4.9600	5.6200	8.9000	7.2900	7.2300
C9	4.4800	4.1700	3.7300	5.8000	7.0500	4.7500
C10+	66.3000	72.0600	63.8500	67.7100	53.9500	59.2600
Benzene	0.0300	0.4300	0.0300	1.0000	1.2400	1.1600
Toluene	0.2900	1.9600	0.1200	2.7600	2.8500	2.3500
E-Benzene	0.2200	0.2400	0.0800	0.2400	0.1800	0.1600
Xylenes	0.6500	1.2100	0.5400	2.5900	1.2300	0.8600
n-C6	2.3200	1.3000	2.7400	0.7500	2.1100	2.5400
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 70	Sample Tank No. 71	Sample Tank No. 72	Sample Tank No. 73	Sample Tank No. 74	Sample Tank No. 75
E&P Tank Number	**Tank No. 24**	**Tank No. 25**	**Tank No. 26**	**Tank No. 27**	**Tank No. 28**	**Tank No. 29**
Total Emissions (tpy)	243.873	502.831	13.397	154.387	119.805	263.134
VOC Emissions (tpy)	151.292	330.274	4.231	125.001	48.333	168.558
Methane Emissions (tpy)	7.881	124.465	6.395	4.603	45.716	54.016
HAP Emissions (tpy)	**2.480**	**13.120**	**0.070**	**10.900**	**1.090**	**3.440**
Benzene	*0.188*	*0.954*	*0.008*	*0.053*	*0.189*	*0.435*
Toluene	*0.276*	*1.256*	*0.003*	*0.110*	*0.076*	*0.413*
E-Benzene	*0.007*	*0.086*	*0.000*	*0.031*	*0.004*	*0.046*
Xylenes	*0.114*	*0.732*	*0.008*	*0.305*	*0.033*	*0.285*
n-C6	*1.896*	*10.096*	*0.055*	*10.401*	*0.785*	*2.257*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	22	280	4	25	64	80
Separator Temperature (F)	98	106	80	180	70	77
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	98	106	80	180	70	77
C10+ SG	0.917	0.921	0.893	0.916	0.898	0.896
C10+ MW	311	450	313	304	368	309
API Gravity	**29.0**	**30.0**	**30.0**	**30.0**	**30.0**	**33.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	6.20	4.80	2.60	2.70	2.80	2.20
GOR (scf/bbl)	24.26	61.80	2.34	11.76	18.78	32.78
Heating Value of Vapor (Btu/s	2141.84	1933.26	1394.74	2814.20	1478.45	1920.70
LP Oil Component						
H2S	1.0100	0.0000	0.0000	0.0300	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.1100	0.1200	0.0200	0.2700	0.1700	0.0300
N2	0.0000	0.0500	0.0000	0.0000	0.0200	0.0200
C1	0.4000	7.9800	0.5900	0.2600	3.1300	2.9000
C2	1.6600	1.5600	0.4000	0.4800	0.7000	1.1000
C3	2.2300	2.8200	0.5500	0.8100	1.0700	1.7100
i-C4	1.1500	1.4300	0.4500	0.3600	0.8800	1.0700
n-C4	1.9500	2.4400	0.6300	1.1800	1.1100	1.1500
i-C5	2.8400	2.1200	0.4800	1.2900	1.0500	1.5000
n-C5	1.3600	2.0900	0.4500	2.0600	1.0000	1.2300
C6	3.0700	2.5400	1.0000	2.6800	1.5300	2.3300
C7	6.9000	6.3500	4.3100	6.5200	4.4300	6.0000
C8	7.6500	8.0300	4.9000	7.3900	5.8900	8.7700
C9	5.8200	3.5600	4.1700	4.8600	4.2200	6.3100
C10+	61.2100	54.9600	80.5100	68.2000	72.4400	60.3600
Benzene	0.1500	0.2000	0.0900	0.0200	0.3100	0.3800
Toluene	0.6100	0.6800	0.1100	0.0900	0.3800	1.0700
E-Benzene	0.0400	0.1100	0.0200	0.0500	0.0500	0.3100
Xylenes	0.7000	1.0600	0.8100	0.5400	0.5000	2.2000
n-C6	1.1400	1.9000	0.5100	2.9100	1.1200	1.5600
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 76	Sample Tank No. 77	Sample Tank No. 78	Sample Tank No. 79	Sample Tank No. 80	Sample Tank No. 81
E&P Tank Number	**Tank No. 30**	**Tank No. 31**	**Tank No. 32**	**Tank No. 33**	**Tank No. 34**	**Tank No. 35**
Total Emissions (tpy)	75.697	67.111	33.481	98.139	246.837	206.565
VOC Emissions (tpy)	48.997	21.176	9.640	41.538	186.576	136.694
Methane Emissions (tpy)	15.026	39.198	18.906	45.393	13.777	5.258
HAP Emissions (tpy)	**1.330**	**0.460**	**0.290**	**1.230**	**7.150**	**4.120**
Benzene	*0.115*	*0.055*	*0.025*	*0.118*	*1.477*	*0.060*
Toluene	*0.088*	*0.025*	*0.040*	*0.085*	*1.336*	*0.122*
E-Benzene	*0.010*	*0.002*	*0.004*	*0.008*	*0.030*	*0.010*
Xylenes	*0.038*	*0.011*	*0.023*	*0.165*	*0.263*	*0.100*
n-C6	*1.075*	*0.362*	*0.196*	*0.852*	*4.047*	*3.833*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	20	60	18	40	18	15
Separator Temperature (F)	115	78	70	110	80	108
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	115	78	70	110	80	108
C10+ SG	0.885	0.866	0.875	0.87	0.923	0.887
C10+ MW	280	324	277	297	346	272
API Gravity	**33.0**	**34.0**	**34.0**	**34.0**	**35.0**	**35.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.10	2.00	2.20	3.20	4.70	4.50
GOR (scf/bbl)	8.96	12.60	6.20	16.18	24.36	18.78
Heating Value of Vapor (Btu/s	1989.27	1308.40	1280.62	1473.81	2361.43	2135.62
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0100	0.0500
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0300	0.0500	0.0700	0.0400	0.0600	0.6100
N2	0.0000	0.0000	0.0000	0.0100	0.0100	0.0500
C1	0.8400	2.8100	1.1600	2.9100	0.6400	0.2600
C2	0.3700	0.3100	0.2400	0.4400	1.0500	0.7800
C3	0.9200	0.6200	0.4900	0.6800	2.2200	1.7400
i-C4	1.0000	0.4700	0.4300	0.5800	0.8300	0.8400
n-C4	1.3200	0.7300	0.6500	0.6300	2.7600	2.3700
i-C5	1.3500	0.7100	0.8000	0.5300	2.1100	2.2400
n-C5	1.2200	0.6600	0.7000	0.4900	3.1100	2.2500
C6	1.8500	1.0800	1.2900	0.8900	3.5800	3.1500
C7	4.6800	2.3500	3.6200	4.6300	11.4200	6.1800
C8	5.5400	2.9600	5.5500	5.3100	11.2400	6.7100
C9	3.8000	1.9300	3.8000	4.5800	8.3200	5.0700
C10+	74.8700	84.1900	78.1200	76.3800	40.2000	64.3300
Benzene	0.1700	0.1100	0.1400	0.1000	1.6600	0.0500
Toluene	0.3400	0.1500	0.6900	0.1900	4.4100	0.2700
E-Benzene	0.0900	0.0300	0.1800	0.0400	0.2500	0.0500
Xylenes	0.3900	0.2000	1.2000	0.9800	2.5500	0.5900
n-C6	1.2200	0.6400	0.8700	0.5900	3.5700	2.4100
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 82	Sample Tank No. 83	Sample Tank No. 84	Sample Tank No. 85	Sample Tank No. 86	Sample Tank No. 87
E&P Tank Number	**Tank No. 36**	**Tank No. 37**	**Tank No. 38**	**Tank No. 39**	**Tank No. 40**	**Tank No. 41**
Total Emissions (tpy)	176.370	34.019	82.578	113.253	204.693	178.190
VOC Emissions (tpy)	121.493	16.601	32.683	56.649	107.904	100.629
Methane Emissions (tpy)	10.526	12.380	40.189	30.738	57.039	28.323
HAP Emissions (tpy)	**3.520**	**1.050**	**1.820**	**2.310**	**3.540**	**2.460**
Benzene	*0.068*	*0.262*	*0.364*	*0.285*	*0.530*	*0.307*
Toluene	*0.092*	*0.297*	*0.293*	*0.292*	*0.386*	*0.280*
E-Benzene	*0.019*	*0.011*	*0.016*	*0.018*	*0.030*	*0.012*
Xylenes	*0.072*	*0.048*	*0.125*	*0.138*	*0.208*	*0.068*
n-C6	*3.266*	*0.435*	*1.023*	*1.573*	*2.383*	*1.789*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	17	30	50	57	75	28
Separator Temperature (F)	100	125	68	80	81	60
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	100	125	68	80	81	60
C10+ SG	0.887	0.863	0.879	0.883	0.883	0.891
C10+ MW	283	276	356	294	288	277
API Gravity	**35.0**	**36.0**	**36.0**	**36.0**	**36.0**	**36.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	4.90	2.50	3.80	3.90	4.10	3.80
GOR (scf/bbl)	17.62	5.02	14.02	15.52	27.84	22.04
Heating Value of Vapor (Btu/s	2307.25	1616.36	1437.32	1721.01	1718.90	1846.39
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.2000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0900	0.0300	0.0300	0.0600	0.1400	0.0600
N2	0.0100	0.0000	0.0100	0.0100	0.0100	0.0100
C1	0.5300	0.9100	2.4200	1.5900	2.9000	1.3300
C2	1.1100	0.3200	0.4500	0.7200	0.9500	0.9300
C3	1.7600	0.5700	0.8100	1.1100	1.4500	1.7200
i-C4	0.8000	0.3900	0.5400	0.7700	1.0000	0.4400
n-C4	2.3800	0.5800	1.1700	1.6000	1.8400	1.9800
i-C5	2.1600	0.6500	1.3400	1.5200	1.6700	1.2300
n-C5	2.6700	0.5700	1.6000	1.6700	1.7900	2.2100
C6	3.3700	1.0700	2.4800	2.5900	2.1500	2.4300
C7	6.0700	3.3600	7.6400	7.1400	6.1000	9.4100
C8	6.8700	5.7300	10.3500	9.7000	7.9700	10.5500
C9	6.0400	4.2600	5.9100	5.1000	5.2600	6.0500
C10+	62.5300	77.9200	57.3100	59.8700	61.4100	54.5600
Benzene	0.0700	0.5500	0.8300	0.5000	0.5100	0.6300
Toluene	0.2600	1.5800	2.0500	1.5100	1.0900	1.8200
E-Benzene	0.1300	0.1300	0.2900	0.2400	0.2200	0.2100
Xylenes	0.5600	0.6500	2.6900	2.1000	1.7300	1.4100
n-C6	2.5900	0.7300	2.0800	2.2000	1.8100	2.8200
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	**Sample Tank No. 88**	**Sample Tank No. 89**	**Sample Tank No. 90**	**Sample Tank No. 91**	**Sample Tank No. 92**	**Sample Tank No. 93**
E&P Tank Number	**Tank No. 42**	**Tank No. 43**	**Tank No. 44**	**Tank No. 45**	**Tank No. 46**	**Tank No. 47**
Total Emissions (tpy)	264.744	77.810	341.571	746.422	120.452	114.826
VOC Emissions (tpy)	197.667	45.796	126.289	598.797	71.033	53.659
Methane Emissions (tpy)	4.156	20.047	121.935	12.450	24.855	41.873
HAP Emissions (tpy)	**5.070**	**1.720**	**2.060**	**7.990**	**1.310**	**1.960**
Benzene	*0.536*	*0.269*	*0.294*	*3.587*	*0.126*	*0.496*
Toluene	*6.120*	*0.232*	*0.161*	*0.449*	*0.199*	*0.291*
E-Benzene	*0.040*	*0.014*	*0.036*	*0.061*	*0.009*	*0.009*
Xylenes	*0.205*	*0.121*	*0.106*	*0.072*	*0.077*	*0.052*
n-C6	*3.677*	*1.081*	*1.462*	*3.820*	*0.900*	*1.109*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	18	18	190	22	24	60
Separator Temperature (F)	95	98	70	50	68	72
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	95	98	70	50	68	72
C10+ SG	0.9	0.871	0.861	0.918	0.872	0.863
C10+ MW	288	270	270	372	239	318
API Gravity	**36.0**	**37.0**	**37.0**	**37.0**	**38.0**	**38.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	7.20	3.90	3.00	4.90	3.60	4.50
GOR (scf/bbl)	23.68	10.02	53.74	67.22	15.46	17.44
Heating Value of Vapor (Btu/s	2352.89	1820.80	1489.35	2491.03	1867.10	1590.85
LP Oil Component						
H2S	0.8700	0.0000	0.0000	0.1400	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.1200	0.0500	0.3100	0.5300	0.0200	0.0500
N2	0.0200	0.0000	0.0300	0.0000	0.0000	0.0000
C1	0.1900	1.0400	6.2500	0.5600	1.1400	2.5500
C2	0.6800	0.4200	2.2000	2.3100	0.5800	0.8600
C3	2.5400	0.9700	2.0200	4.1000	1.2600	1.3500
i-C4	1.1400	1.1500	0.5500	1.9100	0.9300	0.9700
n-C4	3.8100	1.3100	1.1800	5.0000	1.4400	1.3600
i-C5	2.9900	1.6600	0.8300	3.4000	1.6100	1.4200
n-C5	2.9100	1.2800	0.7100	3.5100	1.3900	1.3400
C6	3.7100	2.1200	1.3200	3.0200	2.3200	2.1100
C7	9.0500	5.2700	3.8300	13.2800	6.5000	5.5300
C8	7.1100	7.7200	6.7800	13.1300	8.7200	7.6500
C9	5.9500	4.7200	2.8000	5.9600	5.9100	5.6600
C10+	52.8400	67.1300	69.1900	36.1900	62.7500	64.2400
Benzene	0.4700	0.5000	0.1800	2.6100	0.3100	0.8400
Toluene	1.5000	1.1900	0.3000	1.0600	1.5000	1.4900
E-Benzene	0.2400	0.1800	0.1800	0.4000	0.1800	0.1200
Xylenes	1.4100	1.7200	0.6100	0.5500	1.7900	0.8100
n-C6	2.4500	1.5700	0.7300	2.3400	1.6500	1.6500
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 94	Sample Tank No. 95	Sample Tank No. 96	Sample Tank No. 97	Sample Tank No. 98	Sample Tank No. 99
E&P Tank Number	**Tank No. 48**	**Tank No. 49**	**Tank No. 50**	**Tank No. 51**	**Tank No. 52**	**Tank No. 53**
Total Emissions (tpy)	54.705	437.309	165.905	279.758	608.810	254.487
VOC Emissions (tpy)	37.588	181.269	149.208	103.605	571.582	161.927
Methane Emissions (tpy)	8.963	1.079	0.600	12.141	8.030	48.433
HAP Emissions (tpy)	**2.550**	**4.660**	**4.640**	**1.630**	**17.380**	**7.830**
Benzene	*0.263*	*0.041*	*0.202*	*0.453*	*0.424*	*2.228*
Toluene	*0.317*	*0.110*	*0.380*	*0.085*	*0.458*	*1.268*
E-Benzene	*0.024*	*0.053*	*0.035*	*0.015*	*0.025*	*0.039*
Xylenes	*0.218*	*0.149*	*0.168*	*0.017*	*0.441*	*0.399*
n-C6	*1.726*	*4.311*	*3.855*	*1.063*	*16.032*	*3.892*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	32	62	13	28	22	66
Separator Temperature (F)	149	80	113	45	114	89
Ambient Pressure (psia)	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Temperature (F)	149	80	113	45	114	89
C10+ SG	0.862	0.894	0.882	0.904	0.877	0.877
C10+ MW	251	310	294	294	337	282
API Gravity	**38.0**	**38.0**	**38.0**	**38.0**	**38.0**	**39.0**
Production Rate (bbl/day)	500	500	500	500	500	500
Reid Vapor Pressure (psia)	3.00	5.20	5.70	7.40	3.10	3.70
GOR (scf/bbl)	5.82	37.60	13.60	28.24	45.82	30.08
Heating Value of Vapor (Btu/s	2216.65	1206.29	2853.46	1313.43	3053.30	1945.58
LP Oil Component						
H2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2	0.0100	4.1200	0.0100	2.0000	0.0400	0.1800
N2	0.0000	0.0200	0.0000	0.0000	0.2000	0.0000
C1	0.5100	0.0500	0.0300	0.5300	0.4200	2.2600
C2	0.4400	0.3200	0.4500	1.0400	0.5700	0.8400
C3	0.5900	1.4800	2.4200	1.9800	2.1600	1.4800
i-C4	0.5400	0.8700	1.1900	1.4200	1.1400	1.0300
n-C4	0.6500	3.3500	3.2300	3.7800	4.2600	1.6000
i-C5	1.3500	3.0800	2.0600	2.9700	2.9000	2.0600
n-C5	1.1500	2.8200	3.0500	2.9500	4.2900	1.8600
C6	2.5000	4.7100	2.3400	2.6800	3.5200	3.4100
C7	6.4600	10.0400	7.7900	11.8900	10.3400	8.6400
C8	8.5600	11.8100	8.3700	11.7900	9.9300	11.0300
C9	3.4500	6.4100	6.4400	6.6500	4.4300	5.1000
C10+	69.3200	46.8100	57.0400	45.6300	51.0200	51.2400
Benzene	0.3200	0.0300	0.2000	1.1100	0.1100	1.6600
Toluene	0.9100	0.2400	0.9900	0.7100	0.3100	2.6900
E-Benzene	0.1500	0.3000	0.2100	0.3600	0.0400	0.2100
Xylenes	1.4800	0.9700	1.1500	0.4800	0.7800	2.4200
n-C6	1.6100	2.5700	3.0300	2.0300	3.5400	2.2900
224Trimethylp	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000	100.0000	100.0000

Tank ID	Sample Tank No. 100	Sample Tank No. 101	Sample Tank No. 102	Sample Tank No. 103
E&P Tank Number	**Tank No. 54**	**Tank No. 55**	**Tank No. 56**	**Tank No. 57**
Total Emissions (tpy)	173.095	363.718	391.465	274.631
VOC Emissions (tpy)	97.629	237.995	191.567	204.825
Methane Emissions (tpy)	52.151	56.163	3.830	22.453
HAP Emissions (tpy)	**4.410**	**2.820**	**5.090**	**19.640**
Benzene	*0.242*	*0.369*	*0.970*	*5.674*
Toluene	*0.281*	*0.045*	*0.836*	*4.267*
E-Benzene	*0.031*	*0.026*	*0.019*	*0.070*
Xylenes	*0.164*	*0.129*	*0.135*	*0.436*
n-C6	*3.689*	*2.253*	*3.127*	*9.194*
224Trimethylp	*0.000*	*0.000*	*0.000*	*0.000*
Separator Pressure (psig)	60	60	33	42
Separator Temperature (F)	80	58	60	110
Ambient Pressure (psia)	14.7	14.7	14.7	14.7
Ambient Temperature (F)	60	58	60	110
C10+ SG	0.891	0.877	0.907	0.879
C10+ MW	265	309	295	283
API Gravity	**39.0**	**39.0**	**39.0**	**39.0**
Production Rate (bbl/day)	500	500	500	500
Reid Vapor Pressure (psia)	5.60	6.80	6.40	5.40
GOR (scf/bbl)	23.36	43.14	36.04	26.60
Heating Value of Vapor (Btu/s	1766.66	2016.56	1509.76	2428.31
LP Oil Component				
H2S	0.0000	0.0000	0.1100	0.0000
O2	0.0000	0.0000	0.0000	0.0000
CO2	0.0500	0.0300	2.4000	0.0100
N2	0.0100	0.0100	0.0000	0.0000
C1	2.3200	2.6700	0.1600	1.0900
C2	0.7200	1.7300	0.7600	1.5000
C3	1.1900	3.6000	2.6400	2.1200
i-C4	0.8900	1.8800	0.9100	0.8400
n-C4	1.8300	3.2300	3.5800	2.2800
i-C5	2.3500	2.4900	2.6500	1.6400
n-C5	3.2400	2.1100	3.4400	2.5200
C6	3.9900	2.7200	3.7800	2.6100
C7	9.9400	8.1600	10.7700	9.7300
C8	11.5600	11.9800	11.8300	8.9300
C9	6.0600	4.9500	6.1900	5.8900
C10+	48.9900	50.3400	40.8600	47.7300
Benzene	0.3000	0.3800	1.2700	2.7500
Toluene	1.0300	0.1500	3.4900	5.3000
E-Benzene	0.2900	0.2400	0.2200	0.2000
Xylenes	1.7800	1.3700	1.8000	1.3900
n-C6	3.4600	1.9600	3.1400	3.4700
224Trimethylp	0.0000	0.0000	0.0000	0.0000
	100.0000	100.0000	100.0000	100.0000

					API > 40		
Tank ID							
E&P Tank Number		**Average**	**ratios to HAP**	**Ratio to VOC**	**Maximum**	**Minimum**	**Average**
Total Emissions (tpy)	Total	785.812			8152.118	129.419	1530.229
VOC Emissions (tpy)	VOC	530.750	**33.837**		5678.554	43.734	1046.343
Methane Emissions (tpy)	Methane	116.167	**7.406**	**0.219**	1206.981	0.197	230.569
HAP Emissions (tpy)	**HAP**	**15.685**		**0.030**	**101.610**	**2.680**	**30.684**
Benzene							
Toluene							
E-Benzene							
Xylenes							
n-C6							
224Trimethylp							
Separator Pressure (psig)	Separator Pressure	126.451			870.000	13.000	231.870
Separator Temperature (F)	Separator Temperature	88.657			140.000	40.000	82.500
Ambient Pressure (psia)							
Ambient Temperature (F)							
C10+ SG		0.893			0.929	0.801	0.873
C10+ MW		292.72			375.000	162.000	241.304
API Gravity	**API Gravity**	**40.6**			**68.0**	**40.0**	**52.8**
Production Rate (bbl/day)							
Reid Vapor Pressure (psia)	RVP	5.691			13.100	3.000	7.983
GOR (scf/bbl)	GOR	88.149			924.960	12.300	172.479
Heating Value of Vapor (Btu/s	Heating value	1968.085					
LP Oil Component		**Composition**					
H2S		0.0679					
O2		0.0000					
CO2		0.3661					
N2		0.0360					
C1		2.9248					
C2		1.6262					
C3		2.7564					
i-C4		1.3958					
n-C4		2.9738					
i-C5		2.4711					
n-C5		2.7194					
C6		3.2723					
C7		8.5230					
C8		10.3202					
C9		5.6686					
C10+		48.1339					
Benzene		0.6044					
Toluene		1.6882					
E-Benzene		0.1797					
Xylenes		1.4353					
n-C6		2.8369					
224Trimethylp		0.0000					
		100.0000					

Tank ID	API <40		
E&P Tank Number	**Maximum**	**Minimum**	**Average**
Total Emissions (tpy)	746.422	13.397	174.327
VOC Emissions (tpy)	598.797	3.087	107.227
Methane Emissions (tpy)	124.465	0.115	22.193
HAP Emissions (tpy)	**19.640**	**0.070**	**3.366**
Benzene	5.674	0.003	0.445
Toluene	6.120	0.003	0.431
E-Benzene	0.086	0.000	0.019
Xylenes	0.732	0.001	0.120
n-C6	16.032	0.052	2.449
224Trimethylp	0.000	0.000	0.000
Separator Pressure (psig)	280.000	4.000	39.857
Separator Temperature (F)			
Ambient Pressure (psia)			
Ambient Temperature (F)			
C10+ SG	0.984	0.861	0.910
C10+ MW	551.000	239.000	334.946
API Gravity	**39.0**	**15.0**	**30.6**
Production Rate (bbl/day)			
Reid Vapor Pressure (psia)	7.400	0.600	3.809
GOR (scf/bbl)	67.220	2.340	18.878
Heating Value of Vapor (Btu/s			
LP Oil Component			
H2S			
O2			
CO2			
N2			
C1			
C2			
C3			
i-C4			
n-C4			
i-C5			
n-C5			
C6			
C7			
C8			
C9			
C10+			
Benzene			
Toluene			
E-Benzene			
Xylenes			
n-C6			
224Trimethylp			

API Gravity >40

VOC Emissions (tpy)	
Mean	1046.343
Standard Error	188.1410357
Median	530.989
Mode	#N/A
Standard Deviation	1276.034588
Sample Variance	1628264.269
Kurtosis	3.35522263
Skewness	1.864492873
Range	5634.82
Minimum	43.734
Maximum	5678.554
Sum	48131.778
Count	46
Largest(1)	5678.554
Confidence Level(95.0%)	378.9354921

	667.4075079
VOC	1046.343
	1425.278492

API Gravity <40

VOC Emissions (tpy)	
Mean	107.2265
Standard Error	15.51304
Median	72.87
Mode	#N/A
Standard Deviation	116.0889
Sample Variance	13476.64
Kurtosis	9.02191
Skewness	2.680349
Range	595.71
Minimum	3.087
Maximum	598.797
Sum	6004.685
Count	56
Largest(1)	598.797
Confidence Level(95.0%)	31.08882

	76.1377
VOC	107.2265
	138.3153

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Greater focus needed on methane leakage from natural gas infrastructure

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Natural gas is seen by many as the future of American energy: a fuel that can provide energy independence and reduce greenhouse gas emissions in the process. However, there has also been confusion about the climate implications of increased use of natural gas for electric power and transportation. We propose and illustrate the use of technology warming potentials as a robust and transparent way to compare the cumulative radiative forcing created by alternative technologies fueled by natural gas and oil or coal by using the best available estimates of greenhouse gas emissions from each fuel cycle (i.e., production, transportation and use). We find that a shift to compressed natural gas vehicles from gasoline or diesel vehicles leads to greater radiative forcing of the climate for 80 or 280 yr, respectively, before beginning to produce benefits. Compressed natural gas vehicles could produce climate benefits on all time frames if the well-to-wheels CH_4 leakage were capped at a level 45–70% below current estimates. By contrast, using natural gas instead of coal for electric power plants can reduce radiative forcing immediately, and reducing CH_4 losses from the production and transportation of natural gas would produce even greater benefits. There is a need for the natural gas industry and science community to help obtain better emissions data and for increased efforts to reduce methane leakage in order to minimize the climate footprint of natural gas.

With growing pressure to produce more domestic energy and to reduce greenhouse gas (GHG) emissions, natural gas is increasingly seen as the fossil fuel of choice for the United States as it transitions to renewable sources. Recent reports in the scientific literature and popular press have produced confusion about the climate implications of natural gas (1–5). On the one hand, a shift to natural gas is promoted as climate mitigation because it has lower carbon per unit energy than coal or oil (6). On the other hand, methane (CH_4), the prime constituent of natural gas, is itself a more potent GHG than carbon dioxide (CO_2); CH_4 leakage from the production, transportation and use of natural gas can offset benefits from fuel-switching.

The climatic effect of replacing other fossil fuels with natural gas varies widely by sector (e.g., electricity generation or transportation) and by the fuel being replaced (e.g., coal, gasoline, or diesel fuel), distinctions that have been largely lacking in the policy debate. Estimates of the net climate implications of fuel-switching strategies should be based on complete fuel cycles (e.g., "well-to-wheels") and account for changes in emissions of relevant radiative forcing agents. Unfortunately, such analyses are weakened by the paucity of empirical data addressing CH_4 emissions through the natural gas supply network, hereafter referred to as CH_4 leakage.* The U.S. Environmental Protection Agency (EPA) recently doubled its previous estimate of CH_4 leakage from natural gas systems (6).

In this paper, we illustrate the importance of accounting for fuel-cycle CH_4 leakage when considering the climate impacts of fuel-technology combinations. Using EPA's estimated CH_4 emissions from the natural gas supply, we evaluated the radiative forcing implications of three U.S.-specific fuel-switching scenarios: from gasoline, diesel fuel, and coal to natural gas.

A shift to natural gas and away from other fossil fuels is increasingly plausible because advances in horizontal drilling and hydraulic fracturing technologies have greatly expanded the country's extractable natural gas resources particularly by accessing gas stored in shale deep underground (7). Contrary to previous estimates of CH_4 losses from the "upstream" portions of the natural gas fuel cycle (8, 9), a recent paper by Howarth et al. calculated upstream leakage rates for shale gas to be so large as to imply higher lifecycle GHG emissions from natural gas than from coal (1). (*SI Text*, discusses differences between our paper and Howarth et al.) Howarth et al. estimated CH_4 emissions as a percentage of CH_4 produced over the lifecycle of a well to be 3.6–7.9% for shale gas and 1.7–6.0% for conventional gas. The EPA's latest estimate of the amount of CH_4 released because of leaks and venting in the natural gas network between production wells and the local distribution network is about 570 billion cubic feet for 2009, which corresponds to 2.4% of gross U.S. natural gas production (1.9–3.1% at a 95% confidence level) (6).† EPA's reported uncertainty appears small considering that its current value is double the prior estimate, which was itself twice as high as the previously accepted amount (9).

Comparing the climate implications of CH_4 and CO_2 emissions is complicated because of the much shorter atmospheric lifetime of CH_4 relative to CO_2. On a molar basis, CH_4 produces 37 times more radiative forcing than CO_2.‡ However, because CH_4 is oxidized to CO_2 with an effective lifetime of 12 yr, the integrated, or cumulative, radiative forcings from equi-molar releases of CO_2 and CH_4 eventually converge toward the same value. Determining whether a unit emission of CH_4 is worse for the climate than a unit of CO_2 depends on the time frame considered. Because accelerated rates of warming mean ecosystems and humans have less time to adapt, increased CH_4 emissions due to substitution of natural gas for coal and oil may produce undesirable climate outcomes in the near-term.

The concept of global warming potential (GWP) is commonly used to compare the radiative forcing of different gases relative

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*Challenges also exist in the quantification of CH_4 emissions from the extraction of coal. We use the term "leakage" for simplicity and define it broadly to include all CH_4 emissions in the natural gas supply, both fugitive leaks as well as vented emissions.

†This represents an uncertainty range between −19% and +30% of natural gas system emissions. For CH_4 from petroleum systems (35% of which we assign to the natural gas supply) the uncertainty is −24% to +149%; however, this is only a minor effect because the portion of natural gas supply that comes from oil wells is less than 20%.

‡One-hundred-two times on a mass basis. This value accounts for methane's direct radiative forcing and a 40% enhancement because of the indirect forcing by ozone and stratospheric water vapor (10).

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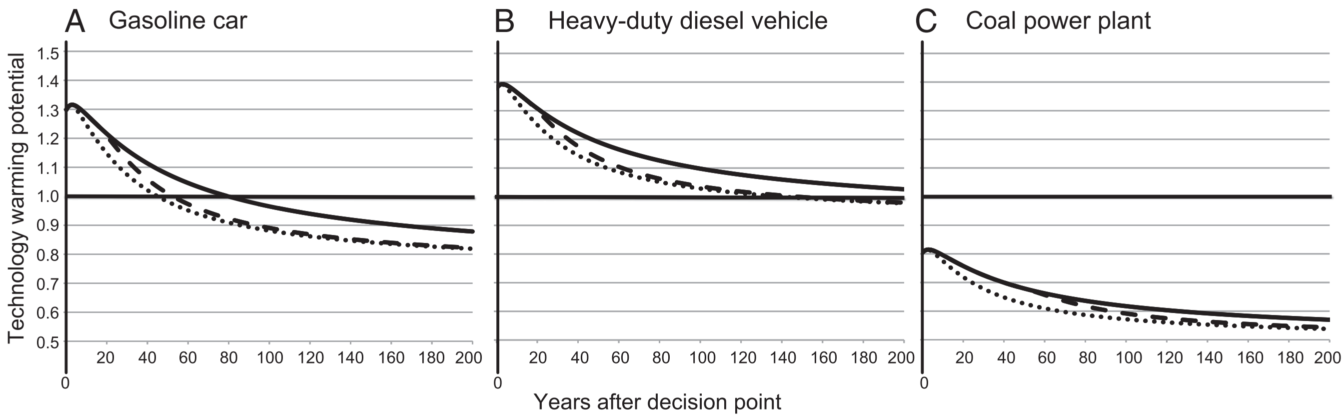

Fig. 1. Technology warming potential (TWP) for three sets of natural gas fuel-switching scenarios. (*A*) CNG light-duty cars vs. gasoline cars; (*B*) CNG heavy-duty vehicles vs. diesel vehicles; and (*C*) combined-cycle natural gas plants vs. supercritical coal plants using low-CH_4 coal. The three curves within each frame simulate real-world choices, including a single emissions pulse (dotted lines); emissions for the full service life of a vehicle or power plant (15 and 50 years, respectively, dashed lines); and emissions from a converted fleet continuing indefinitely (solid lines). For the pulse and service life analyses, our scenarios assume that the natural gas choice reverts back to the incumbent choice before the switch took place; for the fleet conversion analysis we assume that a natural gas vehicle or power plant is replaced by an identical unit at the end of its service life.

to CO_2 and represents the ratio of the cumulative radiative forcing *t* years after emission of a GHG to the cumulative radiative forcing from emission of an equivalent quantity of CO_2 (10). The Intergovernmental Panel on Climate Change (IPCC) typically uses 100 yr for the calculation of GWP. Howarth et al. (1) emphasized the 20-year GWP, which accentuates the large forcing in early years from CH_4 emissions, whereas Venkatesh et al. (2) adopted a 100-yr GWP and Burnham et al. (4) utilized both 20- and 100-yr GWPs.

GWPs were established to allow for comparisons among GHGs at one point in time after emission but only add confusion when evaluating environmental benefits or policy tradeoffs over time. Policy tradeoffs like the ones examined here often involve two or more GHGs with distinct atmospheric lifetimes. A second limitation of GWP-based comparisons is that they only consider the radiative forcing of single emission pulses, which do not capture the climatic consequences of real-world investment and policy decisions that are better simulated as emission streams.

To avoid confusion and enable straightforward comparisons of fuel-technology options, we suggest that plotting as a function of time the relative radiative forcing of the options being considered would be more useful for policy deliberations than GWPs. These technology warming potentials (TWP) require exactly the same inputs and radiative forcing formulas used for GWP but reveal time-dependent tradeoffs inherent in a choice between alternative technologies. We illustrate the value of our approach by applying it to emissions of CO_2 and CH_4 from vehicles fueled with CNG compared with gasoline or diesel vehicles and from power plants fueled with natural gas instead of coal.

Wigley also analyzed changes in the relative benefits over time of switching from coal to natural gas, but that was done in the context of additional complexities including specific assumptions about the global pace of technological substitution, emissions of sulfur dioxide and black carbon, and a specific model of global warming due to radiative forcing (5). We compare our results with Wigley's in the next section.

Results and Discussion

We focus on the TWPs of real-world choices faced by individuals, corporations, and policymakers about fuel-switching in the transport and power sectors. Each of the three curves within the panels of Fig. 1 represents a distinct choice and its associated emission duration: for example, whether to rent a CNG or a gasoline car for a day (Pulse TWP); whether to purchase and operate a CNG or gasoline car for a 15-yr service life (Service-Life TWP); and whether a nation should adopt a policy to convert the gasoline fleet of cars to CNG (Fleet Conversion TWP). In each of these cases, a TWP greater than 1 means that the cumulative radiative forcing from choosing natural gas today is higher than a current fuel option after *t* yr. Our results for pulse TWP at 20 and 100 yr are identical to fuel-cycle analyses using 20-year or 100-year GWPs for CH_4.

Given EPA's current estimates of CH_4 leakage from natural gas production and delivery infrastructure, in addition to a modest CH_4 contribution from the vehicle itself (for which few empirical data are available), CNG-fueled vehicles are not a viable mitigation strategy for climate change.[§] Converting a fleet of gasoline cars to CNG increases radiative forcing for 80 yr before any net climate benefits are achieved; the comparable cross-over point for heavy-duty diesel vehicles is nearly 300 yr.

Stated differently, converting a fleet of cars from gasoline to CNG would result in numerous decades of more rapid climate change because of greater radiative forcing in the early years after the conversion. This is eventually offset by a modest benefit. After 150 yr, a CNG fleet would have produced about 10% less cumulative radiative forcing than a gasoline fleet—a benefit equivalent to a fuel economy improvement of 3 mpg in a 30 mpg fleet. CNG vehicles fare even less favorably in comparison to heavy-duty diesel vehicles.

In contrast to the transportation cases, a fleet of new, combined-cycle natural gas power plants reduces radiative forcing on all time frames, relative to new coal plants burning low-CH_4 coal—assuming current estimates of leakage rates (Fig. 1*C*). The conclusions differ primarily because of coal's higher carbon content relative to petroleum fuels; however, fuel-cycle CH_4 leakage can also affect results. (As discussed elsewhere in this paper, our analysis considered only the emissions of CH_4 and CO_2. In *SI Text*, we examine the effect of different CH_4 leak rates in the coal and natural gas fuel cycles for the electric power scenario.)

To provide guidance to industry and policymakers, we also determined the maximum well-to-wheels or well-to-burner-tip leakage rate needed to ensure net climate benefits on all time frames after fuel-switching to natural gas (see Fig. 2). For example, if the well-to-wheels leakage was reduced to an effective leak rate of 1.6% of natural gas produced (approximately 45% below our estimate of current leakage of 3.0%), CNG cars would result

[§]The CH_4 from operation of a CNG automobile was estimated to be 20 times the value for gasoline vehicles (11), which is approximately 20% of the well-to-pump CH_4 leakage on a kg/mmBtu basis. This assumption deserves much further scrutiny.

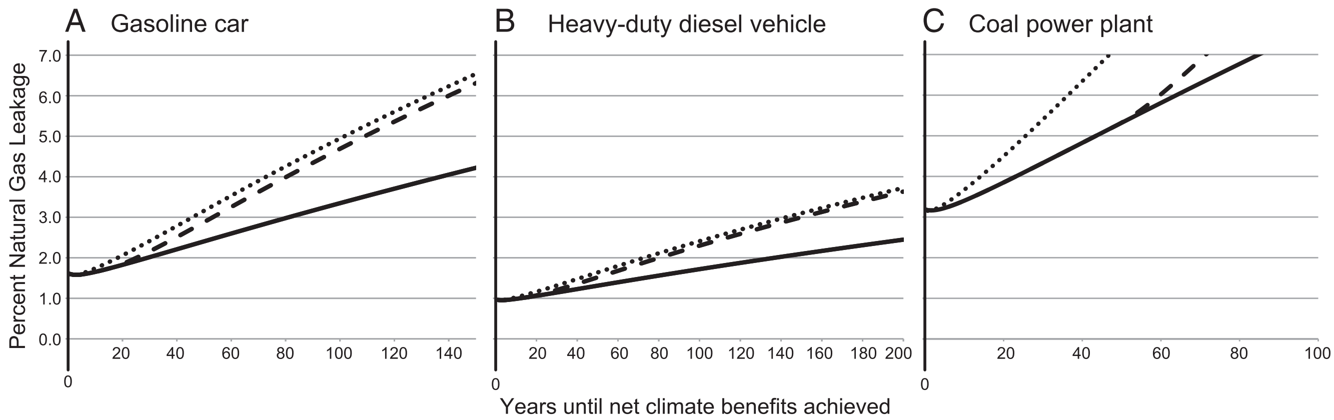

Fig. 2. Maximum "well-to-wheels" natural gas leak rate as a function of the number of years needed to achieve net climate benefits after choosing a CNG option in lieu of (*A*) gasoline cars; (*B*) heavy-duty diesel vehicles; and (*C*) coal power plants. For *A* and *B*, the maximum leakage is the sum of losses from the well through the distribution system plus losses from the CNG vehicle itself (well-to-wheels); for *C*, the maximum leakage is from the well through the transmission system where most power plants receive their fuel. When leak rates are less than the y-intercept, a fuel switch scenario would result in net climate benefits beginning immediately. The three curves within each frame follow the conventions outlined in Fig. 1 and represent: single emissions pulses (dotted lines); the service life of a vehicle or a power plant, 15 or 50 years, respectively (dashed lines); and a permanent fleet conversion (solid lines).

in climate benefits immediately and improve over time.[¶] For CNG to immediately reduce climate impacts from heavy-duty vehicles, well-to-wheels leakage must be reduced below 1%. Fig. 2*C* shows that new natural gas power plants produce net climate benefits relative to efficient, new coal plants using low-gassy coal on all time frames as long as leakage in the natural gas system is less than 3.2% from well through delivery at a power plant. Fig. 2 also shows, for a range of leakage rates, the number of years needed to reach the "cross-over point" when net climate benefits begin to occur after a fuel-technology choice is made.

We emphasize that our calculations assume an average leakage rate for the entire U.S. natural gas supply (as well for coal mining). Much work needs to be done to determine actual emissions with certainty and to accurately characterize the site-to-site variability in emissions. However, given limited current evidence, it is likely that leakage at individual natural gas well sites is high enough, when combined with leakage from downstream operations, to make the total leakage exceed the 3.2% threshold beyond which gas becomes worse for the climate than coal for at least some period of time.[||] Our analysis of reported routine emissions for over 250 well sites with no compressor engines in Barnett Shale gas well sites in Fort Worth, Texas, in 2010 revealed a highly skewed distribution of emissions, with 10% of well sites accounting for nearly 70% of emissions (see *SI Text*).[**] Natural gas leak rates calculated based on operator-reported, daily gas production data at these well sites ranged from 0% to 5%, with six sites out of 203 showing leak rates of 2.6% or greater due to routine emissions alone.[††]

Our analysis of coal-to-natural gas fuel-switching does not consider potential changes in sulfate aerosols and black carbon, short-lived climate forcers previously shown to affect the climate implications of such fuel-switching scenarios (5, 13). Recently, Wigley concluded that coal-to-gas switching on a global scale would result in increased warming on a global scale in the short term, based on examining a set of scenarios with a climate model that included both the increased warming produced by CH_4 losses from the natural gas fuel cycle and the additional cooling that occurs due to SO_2 emissions and the sulfate aerosols they form as a result of burning coal (5). The applicability of Wigley's global conclusion to the United States or any other individual country is limited due to the reliance on global emissions scenarios. Analyses such as Wigley's, which model the climate impacts of all climate forcing emissions, are useful to evaluate specific fuel-switching scenarios; however, their ultimate relevance to policymakers and fleet owners will be determined by the fidelity with which they reflect actual emissions from all phases of each fuel cycle at the relevant geographic scale (e.g., national, continental, or global). The SO_2 emissions that Wigley assumed are much higher than those of the current fleet of coal electrical generation plants in the United States, where SO_2 emissions declined by more than 50% between 2000 and 2010.[‡‡] Moreover, due to state and federal pollution abatement requirements, U.S. SO_2 emissions are projected to continue declining, to roughly 30% of 2000 levels by 2014 (see *SI Text*). This means that by 2014 the projected sulfur emissions from the U.S. coal electrical generation plant fleet, 3 TgS/GtC, will approach the emission factor that Wigley assumed the global fleet would reach in 2060 (2 TgS/GtC), when he projected the climate benefits of fuel-switching might begin, and significantly lower than Wigley's estimated 2010 value of 12 TgS/GtC. Accounting for the lower SO_2 from U.S. coal plants in an integrated way will result in greater net climate impacts of using coal than reported by Wigley and in turn the net benefits of fuel-switching will occur much sooner than he projected.

Increasingly, this will also be the case globally. The production of sulfur aerosols as a result of coal combustion causes such negative impacts on human and ecosystem health that it is prudent to assume that policies will continue to be rapidly implemented in many, if not most, countries to reduce such emissions at a much faster pace than assumed by Wigley. Indeed, it has been reported that China has already installed SO_2 scrubbers on power plants accounting for over 70% of the nation's installed coal power capacity (14), such that SO_2 emissions from power plants in 2010 were 58% below 2004 levels (15). The SO_2 emissions factor from

[¶]Our estimate that current well-to-wheels leakage is 3.0% of gas produced assumes that 2.4% of gas produced is lost between the well and the local distribution system (based on EPA's 2011 GHG emission inventory) and that 0.6% is due to emissions during refueling and from the vehicle itself. For further discussion of the climatic implication of natural gas vehicles see (12).

[||]EPA's GHG inventory suggests leakage from natural gas processing and transmission is 0.6% of gas produced, meaning production leakage must be greater than 2.6% for the total fuel cycle leakage of a power plant receiving fuel from a transmission pipeline to exceed 3.2%.

[**]Sites with compressor engines were excluded due to the contractor's assumption that all engines in the City were uncontrolled, which leads to erroneous emission estimates.

[††]Routine emissions do not include such occasional events as well completions and blowdowns. Only 203 of the 254 sites had data for gas production. An Excel spreadsheet containing the Fort Worth data and our calculations is provided in Dataset S1.

[‡‡]Emissions query performed on December 5, 2011, using the Data and Maps feature of the U.S. Environmental Protection Agency's Clean Air Markets Web page (http://camddataandmaps.epa.gov/gdm/).

Chinese coal plants in 2010 has been estimated to be 204 g/GJ, comparable to the 2010 value of 229 g/GJ (4.7 TgS/GtC) for U.S. coal plants (*SI Text*).

Little work appears to have been done to evaluate fuel-switching in on-road transportation with methods that consider the implications of all climate forcing emissions, including sulfur aerosols and black carbon, although the effect of short-lived climate forcers on individual transport sectors has been studied (16, 17). One study reports that the influence of negative radiative forcing due to emissions from on-road transport is much lower than for the power generation sector in both the United States and globally (18). This implies that our approach, which considers CO_2 and CH_4 emissions alone, provides a reasonable first-order estimate of changes in radiative forcing from fuel-switching scenarios for the on-road transport sector.

Conclusions

The TWP Approach Proposed Here Offers Policymakers Greater Insights than Conventional GWP Analyses. GWPs are a valuable tool to compare the radiative forcing of different gases but are not sufficient when thinking about fuel-switching scenarios. TWPs provide a transparent, policy-relevant analytical approach to examine the time-dependent climate influence of different fuel-technology choices.

Improved Science and Data Are Needed. Despite recent changes to EPA's methodology for estimating CH_4 leakage from natural gas systems, the actual magnitude remains uncertain and estimates could change as methods are refined. Ensuring a high degree of confidence in the climate benefits of natural gas fuel-switching pathways will require better data than are available today. EPA's rule requiring natural gas industry disclosure of GHG emissions should begin to produce data in 2012, though it is unlikely that most uncertainties will be resolved and possible systematic biases eliminated. Specific challenges include confirming the primary sources of emissions and determining drivers of variance in leakage rates. Greater direct involvement of the scientific community could help improve estimates of CH_4 leakage and identify approaches that enable independent validation of industry-reported emissions.

Reductions in CH_4 Leakage Are Needed to Maximize the Climate Benefits of Natural Gas. While CH_4 leakage from natural gas infrastructure and use remains uncertain, it appears that current leakage rates are higher than previously thought. Because CH_4 initially has a much higher effect on radiative forcing than CO_2, maintaining low rates of CH_4 leakage is critical to maximizing the climate benefits of natural gas fuel-technology pathways. Significant progress appears possible given the economic benefits of capturing and selling lost natural gas and the availability of proven technologies. (EPA's Natural Gas STAR program shows many examples: www.epa.gov/gasstar/tools/recommended.html.)

Table 2. Radiative efficiency (RE) values used in this paper

	Direct RE ($W\ m^{-2}\ ppb^{-1}$)	Relative direct + indirect RE (per ppb or molar basis)	Relative direct + indirect RE (per kg basis)*
CO_2	1.4×10^{-5}	1	1
CH_4	3.7×10^{-4}	37	102

*Obtained by multiplying the molar radiative efficiency by the ratio of molecular weights of CH_4 and CO_2.

Methods

Our approach of using TWPs to compare the cumulative radiative forcing of fuel-technology combinations is a straightforward extension of the calculation of GWP, which is given by Eq. **1** over a time horizon, TH, for a pulse emission of 1 kg of a generic GHG producing time-dependent radiative forcing given by $RF_{GHG}(t)$:

$$\mathrm{GWP} = \frac{\int_0^{\mathrm{TH}} \mathrm{RF}_{\mathrm{GHG}}(t)dt}{\int_0^{\mathrm{TH}} \mathrm{RF}_{\mathrm{CO_2}}(t)dt}. \quad [1]$$

SI Text shows the analytical solution of Eq. **1** (i.e., GWP as a function of time horizon). Plotting the entire curve enables one to see the GWP values for all time horizons.

Our TWP approach extends the standard GWP calculation in two ways: by combining the effects of CH_4 and CO_2 emissions from technology-fuel combinations and by considering streams of emissions in addition to single pulses. Considering streams of emissions is more reflective of real-world scenarios that involve activities that occur over multiyear time frames.

Eq. **2** is our extension of the GWP formula Eq. **1** to calculate TWPs, with the following definitions. We label as Technology-1 the alternative that combusts natural gas and has CO_2 emissions E_{1,CO_2} and CH_4 emissions from the production, processing, storage, delivery, and use of the fuel: E_{1,CH_4}. If L_{REF} is the percent of gross natural gas produced that is currently emitted to the atmosphere over the relevant fuel cycle (e.g., electric power or transportation), then Technology-1's CH_4 emissions at leakage rate L would be: $(L/L_{REF})E_{1,CH_4}$. The calculations of TWP in this paper assume that the leakage rate L is at the national average value L_{REF} (and thus $L/L_{REF} = 1$). The scaling factor L/L_{REF} is included to allow calculations about changes in the national leakage rate or about individual wells and distribution networks that deviate from the national average. The values we used for L_{REF} are derived in *SI Text* using EPA's estimated emissions with one exception and are equal to 2.1% for a natural gas power plant and 3.0% for CNG vehicles. The exception to the last statement is that we estimated CH_4 from the operation of a CNG automobile to be 20 times that from a gasoline vehicle (11), which is approximately 20% of the well-to-pump CH_4 leakage on a kg/mmBtu basis. This assumption deserves much further scrutiny. Technology-2 combusts gasoline, diesel fuel, or coal and produces CO_2 emissions E_{2,CO_2} and methane emissions E_{2,CH_4}. Estimates of the Es for each of the technologies considered are reported in Table 1 and are explained in *SI Text*. The TWPs at each point in time can be obtained by substituting the total radiative forcing values, $TRF_{CH_4}(t)$ and $TRF_{CO_2}(t)$ for CH_4 and CO_2, respectively, and emission factors, $E_{n,GHG}$ from Table 1 into Eq. **2**:

Table 1. Emission factors used for TWP calculations in this paper

	Power Plants		Vehicles			
	Natural gas combined cycle* (kg/MW*h*)	Supercritical pulverized coal† (kg/MW*h*)	Light-duty CNG car (kg/mmBtuHHV)‡	Light-duty gasoline car (kg/mmBtuHHV)	Heavy-duty CNG truck (mg/ton-mile)	Heavy-duty diesel truck (mg/ton-mile)
Upstream CH_4	3.1	0.65	0.51	0.1	590	100
Upstream CO_2	36	7	9.4	15.9	10,000	15,000
In-Use CH_4	0	0	0.11	0.0056	15	0
In-Use CO_2	361	807	53.1	70.3	80,000	85,000
Fuel cycle CH_4	3.1	0.65	0.62	0.11	605	100
Fuel cycle CO_2	397	814	62.5	86.2	90,000	100,000

*Heat rate = 6,798 Btu/kWh.
†Heat rate = 8,687 Btu/kWh.
‡1 mmBtu = 10^6 Btu = 1.055 GJ.

Table 3. Total radiative forcing (TRF) functions for CH_4 and CO_2 used in calculation of TWP in Eq. 2 for three distinct emissions profiles

Case	$TRF_{CH_4}(t)$	$TRF_{CO_2}(t)$
Pulse TWP	$RE\{\tau_M(1-e^{-t/\tau_M})\}$	$a_0 t + \sum_{i=1}^{3} a_i\tau_i(1-e^{-t/\tau_i})$
Service Life TWP for $t \le AMAX$	$RE\{\tau_M t - \tau_M^2(1-e^{-t/\tau_M})\}$	$a_0\frac{t^2}{2} + \sum_{i=1}^{3} a_i(\tau_i t - \tau_i^2(1-e^{-t/\tau_i}))$
Service Life TWP for $t > AMAX$	$RE\{\tau_M AMAX - \tau_M^2 e^{-t/\tau_M}(e^{AMAX/\tau_M}-1)\}$	$a_0[AMAX\,t - \frac{AMAX^2}{2}] + \sum_{i=1}^{3} a_i(\tau_i AMAX - \tau_i^2 e^{-t/\tau_i}(e^{AMAX/\tau_i}-1))$
Fleet Conversion TWP	$RE\{\tau_M t - \tau_M^2(1-e^{-t/\tau_M})\}$	$a_0\frac{t^2}{2} + \sum_{i=1}^{3} a_i(\tau_i t - \tau_i^2(1-e^{-t/\tau_i}))$

RE in these formulas is the radiative efficiency of CH_4 relative to CO_2 and equals 102.

$$\mathrm{TWP}(t) = \frac{\frac{L}{L_{\mathrm{REF}}} E_{1,\mathrm{CH_4}} \mathrm{TRF_{CH_4}}(t) + E_{1,\mathrm{CO_2}} \mathrm{TRF_{CO_2}}(t)}{E_{2,\mathrm{CH_4}} \mathrm{TRF_{CH_4}}(t) + E_{2,\mathrm{CO_2}} \mathrm{TRF_{CO_2}}(t)}. \quad [2]$$

The TRF values needed for Eq. **2** are derived as follows. Let $f(t, t_E)$ be the mass of a gas left in the atmosphere at time t if 1 kg of the gas was emitted at time t_E. The cumulative radiative forcing function, $\mathrm{CRF}(t)$ (in units of $J\ m^{-2}\ kg^{-1}$), at a later time t, due to emission of 1 kg of the gas at time t_E, is then:

$$\mathrm{CRF}(t) \equiv \int_{t_E}^{t} \mathrm{RE}\, f(x, t_E)dx, \quad [3]$$

where RE is the radiative efficiency of the gas. The integral in Eq. **3** sums radiative forcing for the $t - t_E$ years from the year in which the gas was emitted, $x = t_E$, to year $x = t$. For simplicity, we adopt units which make the RE of CO_2 equal to one, and so the RE of CH_4 is expressed as a multiple of the RE of CO_2. In these units, the RE of CH_4 is determined to be 102, using the values in Table 2 taken from the IPCC (10) and following the IPCC convention that methane's direct radiative efficiency be enhanced by 25% and 15% to account for indirect forcing due to ozone and stratospheric water, respectively.

Now suppose that instead of a single pulse, the gas is emitted continuously at a rate of 1 kg/yr from $t = 0$ until some maximum time t_{max}, as would occur, for example, if emissions were to continue over the service life of a vehicle, power plant, or fleet. For such cases we define the total radiative forcing (TRF) in year t to be:

$$\mathrm{TRF}(t) \equiv \int_{0}^{t_{\max}} \int_{t_E}^{t} \mathrm{RE}\, f(x, t_E)dx\ dt_E. \quad [4]$$

In the special case of a single emission pulse, $\mathrm{TRF}(t) = \mathrm{CRF}(t)$. Our use of Eq. **4** assumes a constant, unit emission rate; a more general formulation could be employed to reflect potential technology improvements over time.

For CH_4, $f(t, t_E)$ is an exponential decay:

$$f(t, t_E) = e^{-\frac{t - t_E}{\tau_M}}, \quad [5]$$

where τ_M is 12 yr. For CO_2, we follow the IPCC and use the Bern carbon cycle model (10):

$$f(t, t_E) = a_0 + \sum_{i=1}^{3} a_i e^{-\frac{t - t_E}{\tau_i}} \quad [6]$$

where $\tau_1 = 172.9$, $\tau_2 = 18.51$, $\tau_3 = 1.186$, $a_0 = 0.217$, $a_1 = 0.259$, $a_2 = 0.338$, and $a_3 = 0.186$. Our calculations do not consider the CO_2 produced from the oxidation of CH_4, an approximation which introduces a small underestimation of the radiative forcing from a fuel cycle's CH_4 leakage.

If calculating the TWP for a single pulse of emissions (pulse TWP), then $t_E = 0$; $TRF_{CH_4}(t)$ is given by Eq. **3** with $f(t, t_E)$ given by Eq. **5**; and $TRF_{CO_2}(t)$ is given by Eq. **3** with $f(t, t_E)$ given by Eq. **6**. If calculating the TWP for a permanent fuel conversion of a fleet (fleet conversion TWP) then $TRF_{CH_4}(t)$ is given by Eq. **4** with $t_{max} = t$ and $f(t, t_E)$ given by Eq. **5**. Similarly, $TRF_{CO_2}(t)$ is given by Eq. **4** with $t_{max} = t$ and $f(t, t_E)$ given by Eq. **6**. If calculating the TWP for emissions over the service life of a vehicle or power plant (service life TWP) and $t \le AMAX$, where AMAX is the average age at which the asset ceases to emit, then $TRF_{CH_4}(t)$ and $TRF_{CO_2}(t)$ are the same as in the fleet conversion TWP calculations. However, if $t > AMAX$, then $TRF_{CH_4}(t)$ is given by Eq. **4** with $t_{max} = AMAX$ and $f(t, t_E)$ given by Eq. **5**. Similarly, $TRF_{CO_2}(t)$ is given by Eq. **4** with $t_{max} = AMAX$ and $f(t, t_E)$ given by Eq. **6**. The solutions for all of these cases are in Table 3. We use $AMAX = 15$ yr for vehicles and $AMAX = 50$ yr for power plants.

By rearranging terms in Eq. **2** when TWP = 1 to bring L to the left hand side, we obtain an equation for the relationship between the cross-over time (t^*—the time at which the two technologies have equal cumulative radiative forcing) and the percent leakage that makes this happen (L^*):

$$L^* = L_{\mathrm{REF}} \left\{ \frac{E_{2,\mathrm{CH_4}}}{E_{1,\mathrm{CH_4}}} + \frac{E_{2,\mathrm{CO_2}} - E_{1,\mathrm{CO_2}}}{E_{1,\mathrm{CH_4}}} \frac{\mathrm{TRF_{CO_2}}(t^*)}{\mathrm{TRF_{CH_4}}(t^*)} \right\}. \quad [7]$$

Taking the limit of L^* as the cross-over time t^* goes to zero, we obtain an expression for the critical leakage rate L_0, which serves as an approximation of the leakage rate below which the natural gas-burning technology causes less radiative forcing on all time frames.

$$L_0 = L_{\mathrm{REF}} \left\{ \frac{E_{2,\mathrm{CH_4}}}{E_{1,\mathrm{CH_4}}} + \frac{E_{2,\mathrm{CO_2}} - E_{1,\mathrm{CO_2}}}{\mathrm{RE}\ \mathrm{E}_{1,\mathrm{CH_4}}} \right\} \quad [8]$$

where $RE = 102$. Eq. **8** must be viewed as an approximation because L^* is a nonmonotonic function of t^* for small values of t^* (see Fig. 2, which plots L^* as a function of cross-over time t^*). The small decrease in L^* for small t^* is caused by the fact that 18.6% of the emitted CO_2 decays faster than CH_4 in the Bern carbon cycle model (time scales of 1.186 vs. 12 yr). The large increase in L^* for $t_* > 3$ years is caused by the rapid decay of CH_4 relative to the remaining 81.4% of the CO_2. The decay curves for CO_2 and CH_4 are shown in *SI Text*. Calculated values of L_o using Eq. **8** are within 2–3% of the absolute minima for L^*. Calculations of TWP and L^* using Eq. **2** and Eq. **8** were performed with an Excel spreadsheet and are available in Dataset S1.

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Executive Summary

An emissions inventory that identifies and quantifies a country's primary anthropogenic[1] sources and sinks of greenhouse gases is essential for addressing climate change. This inventory adheres to both (1) a comprehensive and detailed set of methodologies for estimating sources and sinks of anthropogenic greenhouse gases, and (2) a common and consistent mechanism that enables Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to compare the relative contribution of different emission sources and greenhouse gases to climate change.

In 1992, the United States signed and ratified the UNFCCC. As stated in Article 2 of the UNFCCC, "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."[2]

Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies…"[3] The United States views this report as an opportunity to fulfill these commitments.

This chapter summarizes the latest information on U.S. anthropogenic greenhouse gas emission trends from 1990 through 2010. To ensure that the U.S. emissions inventory is comparable to those of other UNFCCC Parties, the estimates presented here were calculated using methodologies consistent with those recommended in the Revised 1996 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000), and the IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003). Additionally, the U.S. emission inventory has continued to incorporate new methodologies and data from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The structure of this report is consistent with the UNFCCC guidelines for inventory reporting.[4] For most source categories, the IPCC methodologies were expanded, resulting in a more comprehensive and detailed estimate of emissions.

[BEGIN BOX]

Box ES- 1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the IPCC.[5] Additionally, the calculated emissions and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[6] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that

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[1] The term "anthropogenic," in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC/UNEP/OECD/IEA 1997).

[2] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>.

[3] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

[4] See < http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

[5] See < http://www.ipcc-nggip.iges.or.jp/public/index.html>.

[6] See < http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>.

these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of greenhouse gases (GHG) from large GHG emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). 40 CFR part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO_2 underground for sequestration or other reasons. Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. For calendar year 2010, the first year in which data were reported, facilities in 29 categories provided in 40 CFR part 98 were required to report their 2010 emissions by the September 30, 2011 reporting deadline.[7] The GHGRP dataset and the data presented in this inventory report are complementary and, as indicated in the respective planned improvements sections in this report's chapters, EPA is analyzing how to use facility-level GHGRP data to improve the national estimates presented in this inventory.

[END BOX]

ES.1. Background Information

Naturally occurring greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in their national greenhouse gas emission inventories.[8] Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas emission inventories.

There are also several gases that do not have a direct global warming effect but indirectly affect terrestrial and/or solar radiation absorption by influencing the formation or destruction of greenhouse gases, including tropospheric and stratospheric ozone. These gases include carbon monoxide (CO), oxides of nitrogen (NO_x), and non-CH_4 volatile organic compounds (NMVOCs). Aerosols, which are extremely small particles or liquid droplets, such as those produced by sulfur dioxide (SO_2) or elemental carbon emissions, can also affect the absorptive characteristics of the atmosphere.

Although the direct greenhouse gases CO_2, CH_4, and N_2O occur naturally in the atmosphere, human activities have changed their atmospheric concentrations. From the pre-industrial era (i.e., ending about 1750) to 2010, concentrations of these greenhouse gases have increased globally by 39, 158, and 19 percent, respectively (IPCC 2007 and NOAA/ESLR 2009).

Beginning in the 1950s, the use of CFCs and other stratospheric ozone depleting substances (ODS) increased by nearly 10 percent per year until the mid-1980s, when international concern about ozone depletion led to the entry into force of the Montreal Protocol. Since then, the production of ODS is being phased out. In recent years, use of ODS substitutes such as HFCs and PFCs has grown as they begin to be phased in as replacements for CFCs and

[7] See <http://www.epa.gov/climatechange/emissions/ghgrulemaking.html> and <http://ghgdata.epa.gov/ghgp/main.do>.

[8] Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in the annexes of the Inventory report for informational purposes.

HCFCs. Accordingly, atmospheric concentrations of these substitutes have been growing (IPCC 2007).

Global Warming Potentials

Gases in the atmosphere can contribute to the greenhouse effect both directly and indirectly. Direct effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations of the substance produce other greenhouse gases, when a gas influences the atmospheric lifetimes of other gases, and/or when a gas affects atmospheric processes that alter the radiative balance of the earth (e.g., affect cloud formation or albedo).[9] The IPCC developed the Global Warming Potential (GWP) concept to compare the ability of each greenhouse gas to trap heat in the atmosphere relative to another gas.

The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2001). Direct radiative effects occur when the gas itself is a greenhouse gas. The reference gas used is CO_2, and therefore GWP-weighted emissions are measured in teragrams (or million metric tons) of CO_2 equivalent (Tg CO_2 Eq.).[10,11] All gases in this Executive Summary are presented in units of Tg CO_2 Eq.

The UNFCCC reporting guidelines for national inventories were updated in 2006,[12] but continue to require the use of GWPs from the IPCC Second Assessment Report (SAR) (IPCC 1996). This requirement ensures that current estimates of aggregate greenhouse gas emissions for 1990 to 2010 are consistent with estimates developed prior to the publication of the IPCC Third Assessment Report (TAR) (IPCC 2001) and the IPCC Fourth Assessment Report (AR4) (IPCC 2007). Therefore, to comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. All estimates are provided throughout the report in both CO_2 equivalents and unweighted units. A comparison of emission values using the SAR GWPs versus the TAR and AR4 GWPs can be found in Chapter 1 and, in more detail, in Annex 6.1 of this report. The GWP values used in this report are listed below in Table ES-1.

Table ES-1: Global Warming Potentials (100-Year Time Horizon) Used in this Report

Gas	**GWP**
CO_2	1
CH_4*	21
N_2O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900

Source: IPCC (1996)
* The CH_4 GWP includes the direct effects and those indirect effects due

[9] Albedo is a measure of the Earth's reflectivity, and is defined as the fraction of the total solar radiation incident on a body that is reflected by it.

[10] Carbon comprises 12/44ths of carbon dioxide by weight.

[11] One teragram is equal to 10^{12} grams or one million metric tons.

[12] See <http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Global warming potentials are not provided for CO, NO_x, NMVOCs, SO_2, and aerosols because there is no agreed-upon method to estimate the contribution of gases that are short-lived in the atmosphere, spatially variable, or have only indirect effects on radiative forcing (IPCC 1996).

ES.2. Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2010, total U.S. greenhouse gas emissions were 6,821.8 Tg or million metric tons CO_2 Eq. Total U.S. emissions have increased by 10.5 percent from 1990 to 2010, and emissions increased from 2009 to 2010 by 3.2 percent (213.5 Tg CO_2 Eq.). The increase from 2009 to 2010 was primarily due to an increase in economic output resulting in an increase in energy consumption across all sectors, and much warmer summer conditions resulting in an increase in electricity demand for air conditioning that was generated primarily by combusting coal and natural gas. Since 1990, U.S. emissions have increased at an average annual rate of 0.5 percent.

Figure ES-1 through Figure ES-3 illustrate the overall trends in total U.S. emissions by gas, annual changes, and absolute change since 1990. Table ES-2 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2010.

Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg or million metric tons CO_2 Eq.)

Gas/Source	1990		2005	2006	2007	2008	2009	2010
CO_2	**5,100.5**		**6,107.6**	**6,019.0**	**6,118.6**	**5,924.3**	**5,500.5**	**5,706.4**
Fossil Fuel Combustion	4,738.3		5,746.5	5,653.0	5,757.8	5,571.5	5,206.2	5,387.8
Electricity Generation	1,820.8		2,402.1	2,346.4	2,412.8	2,360.9	2,146.4	2,258.4
Transportation	1,485.9		1,896.6	1,878.1	1,893.9	1,789.8	1,727.9	1,745.5
Industrial	846.4		816.4	848.1	844.4	806.5	726.6	777.8
Residential	338.3		357.9	321.5	341.6	349.3	339.0	340.2
Commercial	219.0		223.5	208.6	218.9	225.1	224.6	224.2
U.S. Territories	27.9		50.0	50.3	46.1	39.8	41.7	41.6
Non-Energy Use of Fuels	119.6		144.1	143.8	134.9	138.6	123.7	125.1
Iron and Steel Production & Metallurgical Coke Production	99.6		66.0	68.9	71.1	66.1	42.1	54.3
Natural Gas Systems	37.6		29.9	30.8	31.0	32.8	32.2	32.3
Cement Production	33.3		45.2	45.8	44.5	40.5	29.0	30.5
Lime Production	11.5		14.4	15.1	14.6	14.3	11.2	13.2
Incineration of Waste	8.0		12.5	12.5	12.7	11.9	11.7	12.1
Limestone and Dolomite Use	5.1		6.8	8.0	7.7	6.3	7.6	10.0
Ammonia Production	13.0		9.2	8.8	9.1	7.9	7.9	8.7
Cropland Remaining Cropland	7.1		7.9	7.9	8.2	8.6	7.2	8.0
Urea Consumption for Non-Agricultural Purposes	3.8		3.7	3.5	4.9	4.1	3.4	4.4
Soda Ash Production and Consumption	4.1		4.2	4.2	4.1	4.1	3.6	3.7
Petrochemical Production	3.3		4.2	3.8	3.9	3.4	2.7	3.3

Aluminum Production	6.8	4.1	3.8	4.3	4.5	3.0	3.0
Carbon Dioxide Consumption	1.4	1.3	1.7	1.9	1.8	1.8	2.2
Titanium Dioxide Production	1.2	1.8	1.8	1.9	1.8	1.6	1.9
Ferroalloy Production	2.2	1.4	1.5	1.6	1.6	1.5	1.7
Zinc Production	0.6	1.0	1.0	1.0	1.2	0.9	1.2
Phosphoric Acid Production	1.5	1.4	1.2	1.2	1.2	1.0	1.0
Wetlands Remaining Wetlands	1.0	1.1	0.9	1.0	1.0	1.1	1.0
Lead Production	0.5	0.6	0.6	0.6	0.5	0.5	0.5
Petroleum Systems	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.1	0.2
Land Use, Land-Use Change, and Forestry (Sink)[a]	*(881.8)*	*(1,085.9)*	*(1,110.4)*	*(1,108.2)*	*(1,087.5)*	*(1,062.6)*	*(1,074.7)*
Wood Biomass and Ethanol Consumption[b]	*218.6*	*228.6*	*233.7*	*241.1*	*252.1*	*244.1*	*266.1*
International Bunker Fuels[c]	*111.8*	*109.8*	*128.4*	*127.6*	*133.7*	*122.3*	*127.8*
CH_4	**668.3**	**625.8**	**664.6**	**656.2**	**667.9**	**672.2**	**666.5**
Natural Gas Systems	189.6	190.5	217.7	205.3	212.7	220.9	215.4
Enteric Fermentation	133.8	139.0	141.4	143.8	143.4	142.6	141.3
Landfills	147.7	112.7	111.7	111.7	113.1	111.2	107.8
Coal Mining	84.1	56.8	58.1	57.8	66.9	70.1	72.6
Manure Management	31.7	47.9	48.4	52.7	51.8	50.7	52.0
Petroleum Systems	35.2	29.2	29.2	29.8	30.0	30.7	31.0
Wastewater Treatment	15.9	16.5	16.7	16.6	16.6	16.5	16.3
Rice Cultivation	7.1	6.8	5.9	6.2	7.2	7.3	8.6
Stationary Combustion	7.5	6.6	6.2	6.5	6.6	6.3	6.3
Abandoned Underground Coal Mines	6.0	5.5	5.5	5.3	5.3	5.1	5.0
Forest Land Remaining Forest Land	2.5	8.1	17.9	14.6	8.8	5.8	4.8
Mobile Combustion	4.7	2.5	2.4	2.2	2.1	2.0	1.9
Composting	0.3	1.6	1.6	1.7	1.7	1.6	1.6
Petrochemical Production	0.9	1.1	1.0	1.0	0.9	0.8	0.9
Iron and Steel Production & Metallurgical Coke Production	1.0	0.7	0.7	0.7	0.6	0.4	0.5
Field Burning of Agricultural Residues	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuesl[c]	0.2	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*	*0.2*
N_2O	**316.2**	**331.9**	**336.8**	**334.9**	**317.1**	**304.0**	**306.2**
Agricultural Soil Management	200.0	213.1	211.1	211.1	212.9	207.3	207.8
Stationary Combustion	12.3	20.6	20.8	21.2	21.1	20.7	22.6
Mobile Combustion	43.9	37.0	33.7	29.0	25.2	22.5	20.6
Manure Management	14.8	17.6	18.4	18.5	18.3	18.2	18.3
Nitric Acid Production	17.6	16.4	16.1	19.2	16.4	14.5	16.7
Wastewater Treatment	3.5	4.7	4.8	4.8	4.9	5.0	5.0
N_2O from Product Uses	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Forest Land Remaining Forest Land	2.1	7.0	15.0	12.2	7.5	5.1	4.3
Adipic Acid Production	15.8	7.4	8.9	10.7	2.6	2.8	2.8
Composting	0.4	1.7	1.8	1.8	1.9	1.8	1.7
Settlements Remaining Settlements	1.0	1.5	1.5	1.6	1.5	1.4	1.4
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*1.1*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*	*1.2*
HFCs	**36.9**	**115.0**	**116.0**	**120.0**	**117.5**	**112.1**	**123.0**
Substitution of Ozone Depleting	0.3	99.0	101.9	102.7	103.6	106.3	114.6

Substances							
HCFC-22 Production	36.4	15.8	13.8	17.0	13.6	5.4	8.1
Semiconductor Manufacture	0.2	0.2	0.3	0.3	0.3	0.3	0.3
PFCs	**20.6**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**	**5.6**
Semiconductor Manufacture	2.2	3.2	3.5	3.7	4.0	4.0	4.1
Aluminum Production	18.4	3.0	2.5	3.8	2.7	1.6	1.6
SF_6	**32.6**	**17.8**	**16.8**	**15.6**	**15.0**	**13.9**	**14.0**
Electrical Transmission and Distribution	26.7	13.9	13.0	12.2	12.2	11.8	11.8
Magnesium Production and Processing	5.4	2.9	2.9	2.6	1.9	1.1	1.3
Semiconductor Manufacture	0.5	1.0	1.0	0.8	0.9	1.0	0.9
Total	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Net Emission (Sources and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

+ Does not exceed 0.05 Tg CO_2 Eq.

[a] Parentheses indicate negative values or sequestration. The net CO_2 flux total includes both emissions and sequestration, and constitutes a net sink in the United States. Sinks are only included in net emissions total.

[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.

[c] Emissions from International Bunker Fuels are not included in totals.

[d] Small amounts of PFC emissions also result from this source.

Note: Totals may not sum due to independent rounding.

Figure ES-4 illustrates the relative contribution of the direct greenhouse gases to total U.S. emissions in 2010. The primary greenhouse gas emitted by human activities in the United States was CO_2, representing approximately 83.6 percent of total greenhouse gas emissions. The largest source of CO_2, and of overall greenhouse gas emissions, was fossil fuel combustion. CH_4 emissions, which have decreased by 0.3 percent since 1990, resulted primarily from natural gas systems, enteric fermentation associated with domestic livestock, and decomposition of wastes in landfills. Agricultural soil management, mobile source fuel combustion and stationary fuel combustion were the major sources of N_2O emissions. Ozone depleting substance substitute emissions and emissions of HFC-23 during the production of HCFC-22 were the primary contributors to aggregate HFC emissions. PFC emissions resulted from semiconductor manufacturing and as a by-product of primary aluminum production, while electrical transmission and distribution systems accounted for most SF_6 emissions.

Figure ES-4: 2010 Greenhouse Gas Emissions by Gas (percentages based on Tg CO_2 Eq.)

Overall, from 1990 to 2010, total emissions of CO_2 increased by 605.9 Tg CO_2 Eq. (11.9 percent), while total emissions of CH_4 and N_2O decreased by 1.7 Tg CO_2 Eq. (0.3 percent), and 10.0 Tg CO_2 Eq. (3.2 percent), respectively. During the same period, aggregate weighted emissions of HFCs, PFCs, and SF_6 rose by 52.5 Tg CO_2 Eq. (58.2 percent). From 1990 to 2010, HFCs increased by 86.1 Tg CO_2 Eq. (233.1 percent), PFCs decreased by 15.0 Tg CO_2 Eq. (72.7 percent), and SF_6 decreased by 18.6 Tg CO_2 Eq. (57.0 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF_6 are significant because many of these gases have extremely high global warming potentials and, in the cases of PFCs and SF_6, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by carbon sequestration in forests, trees in urban areas, agricultural soils, and landfilled yard trimmings and food scraps, which, in aggregate, offset 15.8 percent of total emissions in 2010. The following sections describe each gas's contribution to total U.S. greenhouse gas emissions in more detail.

Carbon Dioxide Emissions

The global carbon cycle is made up of large carbon flows and reservoirs. Billions of tons of carbon in the form of CO_2 are absorbed by oceans and living biomass (i.e., sinks) and are emitted to the atmosphere annually through natural processes (i.e., sources). When in equilibrium, carbon fluxes among these various reservoirs are roughly balanced. Since the Industrial Revolution (i.e., about 1750), global atmospheric concentrations of CO_2 have risen about 39 percent (IPCC 2007 and NOAA/ESLR 2009), principally due to the combustion of fossil fuels. Within the

United States, fossil fuel combustion accounted for 94.4 percent of CO_2 emissions in 2010. Globally, approximately 30,313 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[13] Changes in land use and forestry practices can also emit CO_2 (e.g., through conversion of forest land to agricultural or urban use) or can act as a sink for CO_2 (e.g., through net additions to forest biomass). In addition to fossil-fuel combustion, several other sources emit significant quantities of CO_2. These sources include, but are not limited to non-energy use of fuels, iron and steel production and cement production (Figure ES-5).

Figure ES-5: 2010 Sources of CO_2 Emissions

As the largest source of U.S. greenhouse gas emissions, CO_2 from fossil fuel combustion has accounted for approximately 78 percent of GWP-weighted emissions since 1990, growing slowly from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2010. Emissions of CO_2 from fossil fuel combustion increased at an average annual rate of 0.7 percent from 1990 to 2010. The fundamental factors influencing this trend include (1) a generally growing domestic economy over the last 21 years, and (2) an overall growth in emissions from electricity generation and transportation activities. Between 1990 and 2010, CO_2 emissions from fossil fuel combustion increased from 4,738.3 Tg CO_2 Eq. to 5,387.8 Tg CO_2 Eq.—a 13.7 percent total increase over the twenty-one-year period. From 2009 to 2010, these emissions increased by 181.6 Tg CO_2 Eq. (3.5 percent).

Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends. Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, and seasonal temperatures. In the short term, the overall consumption of fossil fuels in the United States fluctuates primarily in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants. In the long term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Figure ES-6: 2010 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Figure ES-7: 2010 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

The five major fuel consuming sectors contributing to CO_2 emissions from fossil fuel combustion are electricity generation, transportation, industrial, residential, and commercial. CO_2 emissions are produced by the electricity generation sector as they consume fossil fuel to provide electricity to one of the other four sectors, or "end-use" sectors. For the discussion below, electricity generation emissions have been distributed to each end-use sector on the basis of each sector's share of aggregate electricity consumption. This method of distributing emissions assumes that each end-use sector consumes electricity that is generated from the national average mix of fuels according to their carbon intensity. Emissions from electricity generation are also addressed separately after the end-use sectors have been discussed.

Note that emissions from U.S. territories are calculated separately due to a lack of specific consumption data for the individual end-use sectors.

[13] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010a).

Figure ES-6, Figure ES-7, and Table ES-3 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Table ES-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Consuming End-Use Sector (Tg or million metric tons CO_2 Eq.)

End-Use Sector	1990		2005	2006	2007	2008	2009	2010
Transportation	**1,489.0**		**1,901.3**	**1,882.6**	**1,899.0**	**1,794.5**	**1,732.4**	**1,750.0**
Combustion	1,485.9		1,896.6	1,878.1	1,893.9	1,789.8	1,727.9	1,745.5
Electricity	3.0		4.7	4.5	5.1	4.7	4.5	4.5
Industrial	**1,533.1**		**1,553.3**	**1,560.2**	**1,559.8**	**1,503.8**	**1,328.6**	**1,415.4**
Combustion	846.4		816.4	848.1	844.4	806.5	726.6	777.8
Electricity	686.8		737.0	712.0	715.4	697.3	602.0	637.6
Residential	**931.4**		**1,214.7**	**1,152.4**	**1,205.2**	**1,192.2**	**1,125.5**	**1,183.7**
Combustion	338.3		357.9	321.5	341.6	349.3	339.0	340.2
Electricity	593.0		856.7	830.8	863.5	842.9	786.5	843.5
Commercial	**757.0**		**1,027.2**	**1,007.6**	**1,047.7**	**1,041.1**	**978.0**	**997.1**
Combustion	219.0		223.5	208.6	218.9	225.1	224.6	224.2
Electricity	538.0		803.7	799.0	828.8	816.0	753.5	772.9
U.S. Territories[a]	**27.9**		**50.0**	**50.3**	**46.1**	**39.8**	**41.7**	**41.6**
Total	**4,738.3**		**5,746.5**	**5,653.0**	**5,757.8**	**5,571.5**	**5,206.2**	**5,387.8**
Electricity Generation	**1,820.8**		**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,146.4**	**2,258.4**

Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.
[a] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report.

Transportation End-Use Sector. Transportation activities (excluding international bunker fuels) accounted for 32 percent of CO_2 emissions from fossil fuel combustion in 2010.[14] Virtually all of the energy consumed in this end-use sector came from petroleum products. Nearly 65 percent of the emissions resulted from gasoline consumption for personal vehicle use. The remaining emissions came from other transportation activities, including the combustion of diesel fuel in heavy-duty vehicles and jet fuel in aircraft. From 1990 to 2010, transportation emissions rose by 18 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 34 percent from 1990 to 2010, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

Industrial End-Use Sector. Industrial CO_2 emissions, resulting both directly from the combustion of fossil fuels and indirectly from the generation of electricity that is consumed by industry, accounted for 26 percent of CO_2 from fossil fuel combustion in 2010. Approximately 55 percent of these emissions resulted from direct fossil fuel combustion to produce steam and/or heat for industrial processes. The remaining emissions resulted from consuming electricity for motors, electric furnaces, ovens, lighting, and other applications. In contrast to the other end-use sectors, emissions from industry have steadily declined since 1990. This decline is due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements.

Residential and Commercial End-Use Sectors. The residential and commercial end-use sectors accounted for 22 and 19 percent, respectively, of CO_2 emissions from fossil fuel combustion in 2010. Both sectors relied heavily on electricity for meeting energy demands, with 71 and 78 percent, respectively, of their emissions attributable to electricity consumption for lighting, heating, cooling, and operating appliances. The remaining emissions were due to the consumption of natural gas and petroleum for heating and cooking. Emissions from these end-use sectors have increased 29 percent since 1990, due to increasing electricity consumption for lighting, heating, air conditioning, and operating appliances.

[14] If emissions from international bunker fuels are included, the transportation end-use sector accounted for 34.0 percent of U.S. emissions from fossil fuel combustion in 2010.

Electricity Generation. The United States relies on electricity to meet a significant portion of its energy demands. Electricity generators consumed 36 percent of U.S. energy from fossil fuels and emitted 42 percent of the CO_2 from fossil fuel combustion in 2010. The type of fuel combusted by electricity generators has a significant effect on their emissions. For example, some electricity is generated with low CO_2 emitting energy technologies, particularly non-fossil options such as nuclear, hydroelectric, or geothermal energy. However, electricity generators rely on coal for over half of their total energy requirements and accounted for 94 percent of all coal consumed for energy in the United States in 2010. Consequently, changes in electricity demand have a significant impact on coal consumption and associated CO_2 emissions.

Other significant CO_2 trends included the following:

- CO_2 emissions from non-energy use of fossil fuels have increased 5.5 Tg CO_2 Eq. (4.6 percent) from 1990 through 2010. Emissions from non-energy uses of fossil fuels were 125.1 Tg CO_2 Eq. in 2010, which constituted 2.2 percent of total national CO_2 emissions, approximately the same proportion as in 1990.
- CO_2 emissions from iron and steel production and metallurgical coke production increased by 12.2 Tg CO_2 Eq. (28.9 percent) from 2009 to 2010, upsetting a trend of decreasing emissions. Despite this, from 1990 through 2010 emissions declined by 45.5 percent (45.3 Tg CO_2 Eq.). This decline is due to the restructuring of the industry, technological improvements, and increased scrap utilization.
- In 2010, CO_2 emissions from cement production increased by 1.5 Tg CO_2 Eq. (5.1 percent) from 2009. After decreasing in 1991 by two percent from 1990 levels, cement production emissions grew every year through 2006; emissions decreased in the three years prior to 2010. Overall, from 1990 to 2010, emissions from cement production have decreased by 8.3 percent, a decrease of 2.8 Tg CO_2 Eq.
- Net CO_2 uptake from Land Use, Land-Use Change, and Forestry increased by 192.8 Tg CO_2 Eq. (21.9 percent) from 1990 through 2010. This increase was primarily due to an increase in the rate of net carbon accumulation in forest carbon stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual carbon accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of carbon accumulation in urban trees increased.

Methane Emissions

Methane (CH_4) is more than 20 times as effective as CO_2 at trapping heat in the atmosphere (IPCC 1996). Over the last two hundred and fifty years, the concentration of CH_4 in the atmosphere increased by 158 percent (IPCC 2007). Anthropogenic sources of CH_4 include natural gas and petroleum systems, agricultural activities, landfills, coal mining, wastewater treatment, stationary and mobile combustion, and certain industrial processes (see Figure ES-8).

Figure ES-8: 2010 Sources of CH_4 Emissions

Some significant trends in U.S. emissions of CH_4 include the following:

- Natural gas systems were the largest anthropogenic source category of CH_4 emissions in the United States in 2010 with 215.4 Tg CO_2 Eq. of CH_4 emitted into the atmosphere. Those emissions have increased by 25.8 Tg CO_2 Eq. (13.6 percent) since 1990.
- Enteric fermentation is the second largest anthropogenic source of CH_4 emissions in the United States. In 2010, enteric fermentation CH_4 emissions were 141.3 Tg CO_2 Eq. (21.2 percent of total CH_4 emissions), which represents an increase of 7.5 Tg CO_2 Eq. (5.6 percent) since 1990.
- Landfills are the third largest anthropogenic source of CH_4 emissions in the United States, accounting for 16.2 percent of total CH_4 emissions (107.8 Tg CO_2 Eq.) in 2010. From 1990 to 2010, CH_4 emissions from landfills decreased by 39.8 Tg CO_2 Eq. (27.0 percent), with small increases occurring in some interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas

collected and combusted,[15] which has more than offset the additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.

- In 2010, CH_4 emissions from coal mining were 72.6 Tg CO_2 Eq., a 2.5 Tg CO_2 Eq. (3.5 percent) increase over 2009 emission levels. The overall decline of 11.5 Tg CO_2 Eq. (13.6 percent) from 1990 results from the mining of less gassy coal from underground mines and the increased use of CH_4 collected from degasification systems.
- Methane emissions from manure management increased by 64.0 percent since 1990, from 31.7 Tg CO_2 Eq. in 1990 to 52.0 Tg CO_2 Eq. in 2010. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH_4 emissions. The increase in liquid systems is the combined result of a shift to larger facilities, and to facilities in the West and Southwest, all of which tend to use liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site.

Nitrous Oxide Emissions

N_2O is produced by biological processes that occur in soil and water and by a variety of anthropogenic activities in the agricultural, energy-related, industrial, and waste management fields. While total N_2O emissions are much lower than CO_2 emissions, N_2O is approximately 300 times more powerful than CO_2 at trapping heat in the atmosphere (IPCC 1996). Since 1750, the global atmospheric concentration of N_2O has risen by approximately 19 percent (IPCC 2007). The main anthropogenic activities producing N_2O in the United States are agricultural soil management, fuel combustion in motor vehicles, stationary fuel combustion, manure management and nitric acid production (see Figure ES-9).

Figure ES-9: 2010 Sources of N_2O Emissions

Some significant trends in U.S. emissions of N_2O include the following:

- In 2010, N_2O emissions from mobile combustion were 20.6 Tg CO_2 Eq. (approximately 6.7 percent of U.S. N_2O emissions). From 1990 to 2010, N_2O emissions from mobile combustion decreased by 53.1 percent. However, from 1990 to 1998 emissions increased by 25.6 percent, due to control technologies that reduced NO_x emissions while increasing N_2O emissions. Since 1998, newer control technologies have led to an overall decline in N_2O from this source.
- N_2O emissions from adipic acid production were 2.8 Tg CO_2 Eq. in 2010, and have decreased significantly in recent years due to the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 82.2 percent since 1990 and by 84.0 percent since a peak in 1995.
- N_2O emissions from stationary combustion increased 10.3 Tg CO_2 Eq. (84.4 percent) from 1990 through 2010. N_2O emissions from this source increased primarily as a result of an increase in the number of coal fluidized bed boilers in the electric power sector.
- Agricultural soils accounted for approximately 67.9 percent of N_2O emissions in the United States in 2010. Estimated emissions from this source in 2010 were 207.8 Tg CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2010, although overall emissions were 3.9 percent higher in 2010 than in 1990.

HFC, PFC, and SF_6 Emissions

HFCs and PFCs are families of synthetic chemicals that are used as alternatives to ODS, which are being phased out under the Montreal Protocol and Clean Air Act Amendments of 1990. HFCs and PFCs do not deplete the

[15] The CO_2 produced from combusted landfill CH_4 at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

stratospheric ozone layer, and are therefore acceptable alternatives under the Montreal Protocol.

These compounds, however, along with SF_6, are potent greenhouse gases. In addition to having high global warming potentials, SF_6 and PFCs have extremely long atmospheric lifetimes, resulting in their essentially irreversible accumulation in the atmosphere once emitted. Sulfur hexafluoride is the most potent greenhouse gas the IPCC has evaluated (IPCC 1996).

Other emissive sources of these gases include electrical transmission and distribution systems, HCFC-22 production, semiconductor manufacturing, aluminum production, and magnesium production and processing (see Figure ES-10).

Figure ES-10: 2010 Sources of HFCs, PFCs, and SF_6 Emissions

Some significant trends in U.S. HFC, PFC, and SF_6 emissions include the following:

- Emissions resulting from the substitution of ozone depleting substances (ODS) (e.g., CFCs) have been consistently increasing, from small amounts in 1990 to 114.6 Tg CO_2 Eq. in 2010. Emissions from ODS substitutes are both the largest and the fastest growing source of HFC, PFC, and SF_6 emissions. These emissions have been increasing as phase-out of ODS required under the Montreal Protocol came into effect, especially after 1994, when full market penetration was made for the first generation of new technologies featuring ODS substitutes.
- HFC emissions from the production of HCFC-22 decreased by 77.8 percent (28.3 Tg CO_2 Eq.) from 1990 through 2010, due to a steady decline in the emission rate of HFC-23 (i.e., the amount of HFC-23 emitted per kilogram of HCFC-22 manufactured) and the use of thermal oxidation at some plants to reduce HFC-23 emissions.
- SF_6 emissions from electric power transmission and distribution systems decreased by 55.7 percent (14.9 Tg CO_2 Eq.) from 1990 to 2010, primarily because of higher purchase prices for SF_6 and efforts by industry to reduce emissions.
- PFC emissions from aluminum production decreased by 91.5 percent (16.9 Tg CO_2 Eq.) from 1990 to 2010, due to both industry emission reduction efforts and declines in domestic aluminum production.

ES.3. Overview of Sector Emissions and Trends

In accordance with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), and the 2003 UNFCCC Guidelines on Reporting and Review (UNFCCC 2003), Figure ES-11 and Table ES-4 aggregate emissions and sinks by these chapters. Emissions of all gases can be summed from each source category from IPCC guidance. Over the twenty-one-year period of 1990 to 2010, total emissions in the Energy and Agriculture sectors grew by 645.8 Tg CO_2 Eq. (12.2 percent), and 40.6 Tg CO_2 Eq. (10.5 percent), respectively. Emissions slightly decreased in the Industrial Processes sector by 10.5 Tg CO_2 Eq. (3.4 percent) , while emissions from the Waste and Solvent and Other Product Use sectors decreased by 35.2 Tg CO_2 Eq. (21.0 percent) and less than 0.1 Tg CO_2 Eq. (0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry (LULUCF) sector (magnitude of emissions plus CO_2 flux from all LULUCF source categories) increased by 187.0 Tg CO_2 Eq. (21.5 percent).

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg or million metric tons CO_2 Eq.)

Chapter/IPCC Sector	1990		2005	2006	2007	2008	2009	2010
Energy	5,287.7		6,282.4	6,214.4	6,294.3	6,125.4	5,752.7	5,933.5
Industrial Processes	313.9		330.1	335.5	347.3	319.1	268.2	303.4

Solvent and Other Product Use	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Agriculture	387.8	424.6	425.4	432.6	433.8	426.4	428.4
Land-Use Change and Forestry	13.8	25.6	43.2	37.6	27.4	20.6	19.6
Waste	167.7	137.2	136.5	136.7	138.2	136.0	132.5
Total Emissions	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land-Use Change and Forestry (Sinks)	(881.8)	(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Emissions and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

* The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total.

Note: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Energy

The Energy chapter contains emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions. Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2010. In 2010, approximately 85 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 15 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure ES-12). Energy-related activities are also responsible for CH_4 and N_2O emissions (50 percent and 14 percent of total U.S. emissions of each gas, respectively). Overall, emission sources in the Energy chapter account for a combined 87.0 percent of total U.S. greenhouse gas emissions in 2010.

Figure ES-12: 2010 U.S. Energy Consumption by Energy Source

Industrial Processes

The Industrial Processes chapter contains by-product or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production. Additionally, emissions from industrial processes release HFCs, PFCs, and SF_6. Overall, emission sources in the Industrial Process chapter account for 4.4 percent of U.S. greenhouse gas emissions in 2010.

Solvent and Other Product Use

The Solvent and Other Product Use chapter contains greenhouse gas emissions that are produced as a by-product of various solvent and other product uses. In the United States, emissions from N_2O from product uses, the only source of greenhouse gas emissions from this sector, accounted for about 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a carbon equivalent basis in 2010.

Agriculture

The Agricultural chapter contains anthropogenic emissions from agricultural activities (except fuel combustion, which is addressed in the Energy chapter, and agricultural CO_2 fluxes, which are addressed in the Land Use, Land-Use Change, and Forestry Chapter). Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues. CH_4 and N_2O were the primary greenhouse gases emitted by agricultural activities. CH_4 emissions from enteric fermentation and manure management represented 21.2 percent and 7.8 percent of total CH_4 emissions from anthropogenic activities, respectively, in 2010. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N_2O emissions in 2010, accounting for 67.9 percent. In 2010, emission sources accounted for in the Agricultural chapters were responsible for 6.3 percent of total U.S. greenhouse gas emissions.

Land Use, Land-Use Change, and Forestry

The Land Use, Land-Use Change, and Forestry chapter contains emissions of CH_4 and N_2O, and emissions and removals of CO_2 from forest management, other land-use activities, and land-use change. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps resulted in a net uptake (sequestration) of C in the United States. Forests (including vegetation, soils, and harvested wood) accounted for 86 percent of total 2010 net CO_2 flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2010. The net forest sequestration is a result of net forest growth and increasing forest area, as well as a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth in these areas. In agricultural soils, mineral and organic soils sequester approximately 5 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to permanent pastures and hay production, a reduction in summer fallow areas in semi-arid areas, an increase in the adoption of conservation tillage practices, and an increase in the amounts of organic fertilizers (i.e., manure and sewage sludge) applied to agriculture lands. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2010 resulted in a net C sequestration of 1,074.7 Tg CO_2 Eq. (Table ES-5). This represents an offset of 18.8 percent of total U.S. CO_2 emissions, or 15.8 percent of total greenhouse gas emissions in 2010. Between 1990 and 2010, total land use, land-use change, and forestry net C flux resulted in a 21.9 percent increase in CO_2 sequestration, primarily due to an increase in the rate of net C accumulation in forest C stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual C accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of annual C accumulation increased in urban trees.

Table ES-5: Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Sink Category	**1990**		**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Forest Land Remaining Forest Land	(701.4)		(940.9)	(963.5)	(959.2)	(938.3)	(910.6)	(921.8)
Cropland Remaining Cropland	(29.4)		(18.3)	(19.1)	(19.7)	(18.1)	(17.4)	(15.6)
Land Converted to Cropland	2.2		5.9	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)		(8.9)	(8.8)	(8.6)	(8.5)	(8.3)	(8.3)
Land Converted to Grassland	(19.8)		(24.4)	(24.2)	(24.0)	(23.8)	(23.6)	(23.6)
Settlements Remaining Settlements	(57.1)		(87.8)	(89.8)	(91.9)	(93.9)	(95.9)	(98.0)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)		(11.6)	(11.0)	(10.9)	(10.9)	(12.7)	(13.3)
Total	**(881.8)**		**(1,085.9)**	**(1,110.4)**	**(1,108.2)**	**(1,087.5)**	**(1,062.6)**	**(1,074.7)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table ES-6. Liming of agricultural soils and urea fertilization in 2010 resulted in CO_2 emissions of 3.9 Tg CO_2 Eq. (3,906 Gg) and 4.1 Tg CO_2 Eq. (4,143 Gg), respectively. Lands undergoing peat extraction (i.e., *Peatlands Remaining Peatlands*) resulted in CO_2 emissions of 1.0 Tg CO_2 Eq. (983 Gg), and N_2O emissions of less than 0.05 Tg CO_2 Eq. The application of synthetic fertilizers to forest soils in 2010 resulted in direct N_2O emissions of 0.4 Tg CO_2 Eq. (1 Gg). Direct N_2O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, direct N_2O emissions from fertilizer application to settlement soils in 2010 accounted for 1.4 Tg CO_2 Eq. (5 Gg). This represents an increase of 43 percent since 1990. Forest fires in 2010 resulted in CH_4 emissions of 4.8 Tg CO_2 Eq. (231 Gg), and in N_2O emissions of 4.0 Tg CO_2 Eq. (14 Gg).

Table ES-6: Emissions from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Source Category	1990	2005	2006	2007	2008	2009	2010
CO_2	**8.1**	**8.9**	**8.8**	**9.2**	**9.6**	**8.3**	**9.0**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.2	4.5	5.0	3.7	3.9
Cropland Remaining Cropland: Urea Fertilization	2.4	3.5	3.7	3.8	3.6	3.6	4.1
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.1	0.9	1.0	1.0	1.1	1.0
CH_4	**2.5**	**8.1**	**17.9**	**14.6**	**8.8**	**5.8**	**4.8**
Forest Land Remaining Forest Land: Forest Fires	2.5	8.1	17.9	14.6	8.8	5.8	4.8
N_2O	**3.1**	**8.5**	**16.5**	**13.8**	**9.0**	**6.5**	**5.7**
Forest Land Remaining Forest Land: Forest Fires	2.1	6.6	14.6	11.9	7.2	4.7	4.0
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.5	1.5	1.6	1.5	1.4	1.4
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**13.8**	**25.6**	**43.2**	**37.6**	**27.4**	**20.6**	**19.6**

+ Less than 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Waste

The Waste chapter contains emissions from waste management activities (except incineration of waste, which is addressed in the Energy chapter). Landfills were the largest source of anthropogenic greenhouse gas emissions in the Waste chapter, accounting for 81.4 percent of this chapter's emissions, and 16.2 percent of total U.S. CH_4 emissions.[16] Additionally, wastewater treatment accounts for 16.1 percent of Waste emissions, 2.5 percent of U.S. CH_4 emissions, and 1.6 percent of U.S. N_2O emissions. Emissions of CH_4 and N_2O from composting are also accounted for in this chapter; generating emissions of 1.6 Tg CO_2 Eq. and 1.7 Tg CO_2 Eq., respectively. Overall, emission sources accounted for in the Waste chapter generated 1.9 percent of total U.S. greenhouse gas emissions in 2010.

ES.4. Other Information

Emissions by Economic Sector

Throughout the Inventory of U.S. Greenhouse Gas Emissions and Sinks report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC: Energy; Industrial Processes; Solvent Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following economic sectors: Residential, Commercial, Industry, Transportation, Electricity Generation, Agriculture, and U.S. Territories.

Table ES-7 summarizes emissions from each of these sectors, and Figure ES-13 shows the trend in emissions by sector from 1990 to 2010.

Figure ES-13: Emissions Allocated to Economic Sectors

[16] Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land-Use, Land-Use Change, and Forestry chapter of the Inventory report.

Table ES-7: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg or million metric tons CO_2 Eq.)

Implied Sectors	1990		2005	2006	2007	2008	2009	2010
Electric Power Industry	1,866.2		2,448.8	2,393.0	2,459.1	2,405.8	2,191.4	2,306.5
Transportation	1,545.2		2,017.5	1,994.5	2,002.4	1,889.8	1,819.3	1,834.0
Industry	1,564.8		1,438.1	1,499.8	1,489.6	1,448.5	1,317.2	1,394.2
Agriculture	431.9		496.0	516.7	517.6	505.8	492.8	494.8
Commercial	388.0		374.3	359.9	372.2	381.8	382.0	381.7
Residential	345.4		371.3	336.1	358.4	368.4	360.0	365.2
U.S. Territories	33.7		58.2	59.3	53.5	48.4	45.5	45.5
Total Emissions	**6,175.2**		**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land Use, Land-Use Change, and Forestry (Sinks)	(881.8)		(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Sources and Sinks)	**5,293.4**		**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

Note: Totals may not sum due to independent rounding. Emissions include CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6. See Table 2-12 for more detailed data.

Using this categorization, emissions from electricity generation accounted for the largest portion (34 percent) of U.S. greenhouse gas emissions in 2010. Transportation activities, in aggregate, accounted for the second largest portion (27 percent), while emissions from industry accounted for the third largest portion (20 percent) of U.S. greenhouse gas emissions in 2010. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and energy efficiency improvements. The remaining 19 percent of U.S. greenhouse gas emissions were contributed by, in order of importance, the agriculture, commercial, and residential sectors, plus emissions from U.S. territories. Activities related to agriculture accounted for 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation. The commercial and residential sectors accounted for 6 and 5 percent, respectively, of emissions and U.S. territories accounted for 1 percent of emissions; emissions from these sectors primarily consisted of CO_2 emissions from fossil fuel combustion.

CO_2 was also emitted and sequestered by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Electricity is ultimately consumed in the economic sectors described above. Table ES-8 presents greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). To distribute electricity emissions among end-use sectors, emissions from the source categories assigned to electricity generation were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity.[17] These source categories include CO_2 from fossil fuel combustion and the use of limestone and dolomite for flue gas desulfurization, CO_2 and N_2O from incineration of waste, CH_4 and N_2O from stationary sources, and SF_6 from electrical transmission and distribution systems.

When emissions from electricity are distributed among these sectors, industrial activities account for the largest share of U.S. greenhouse gas emissions (30 percent) in 2010. Transportation is the second largest contributor to total U.S. emissions (27 percent). The residential and commercial sectors contributed the next largest shares of total U.S. greenhouse gas emissions in 2010. Emissions from these sectors increase substantially when emissions from electricity are included, due to their relatively large share of electricity consumption (e.g., lighting, appliances, etc.). In all sectors except agriculture, CO_2 accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels. Figure ES-14 shows the trend in these emissions by sector from 1990 to 2010.

Table ES-8: U.S Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed

[17] Emissions were not distributed to U.S. territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

(Tg or million metric tons CO_2 Eq.)

Implied Sectors	1990		2005	2006	2007	2008	2009	2010
Industry	2,237.7		2,159.9	2,198.5	2,185.9	2,131.5	1,905.8	2,019.0
Transportation	1,548.3		2,022.3	1,999.1	2,007.6	1,894.6	1,823.9	1,838.6
Residential	953.2		1,244.6	1,183.4	1,238.5	1,227.3	1,162.9	1,226.6
Commercial	939.4		1,193.6	1,174.8	1,216.9	1,213.3	1,151.3	1,171.0
Agriculture	462.9		525.5	544.2	550.5	533.3	518.9	521.1
U.S. Territories	33.7		58.2	59.3	53.5	48.4	45.5	45.5
Total Emissions	**6,175.2**		**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land Use, Land-Use Change, and Forestry (Sinks)	(881.8)		(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Sources and Sinks)	**5,293.4**		**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

See Table 2-14 for more detailed data.

Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

[BEGIN BOX]

Box ES- 2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and nonutilities combined—was the largest source of U.S. greenhouse gas emissions in 2010; (4) emissions per unit of total gross domestic product as a measure of national economic activity; and (5) emissions per capita.

Table ES-9 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.5 percent since 1990. This rate is slightly slower than that for total energy and for fossil fuel consumption, and much slower than that for electricity consumption, overall gross domestic product and national population (see Figure ES-15).

Table ES-9: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	1990		2005	2006	2007	2008	2009	2010	Growth Rate[a]
GDP[b]	100		157	161	165	164	158	163	2.5%
Electricity Consumption[c]	100		134	135	137	136	131	137	1.6%
Fossil Fuel Consumption[c]	100		119	117	119	116	109	113	0.6%
Energy Consumption[c]	100		119	118	121	119	113	117	0.8%
Population[d]	100		118	120	121	122	123	123	1.1%
Greenhouse Gas Emissions[e]	100		117	116	117	114	107	110	0.5%

[a] Average annual growth rate
[b] Gross Domestic Product in chained 2005 dollars (BEA 2010)
[c] Energy content-weighted values (EIA 2010b)
[d] U.S. Census Bureau (2010)
[e] GWP-weighted values

Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product
Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in this report.

[END BOX]

Indirect Greenhouse Gases (CO, NO_x, NMVOCs, and SO_2)

The reporting requirements of the UNFCCC[18] request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO_2. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases.

Since 1970, the United States has published estimates of annual emissions of CO, NO_x, NMVOCs, and SO_2 (EPA 2010, EPA 2009),[19] which are regulated under the Clean Air Act. Table ES-10 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO_x, and NMVOCs.

Table ES-10: Emissions of NO_x, CO, NMVOCs, and SO_2 (Gg)

Gas/Activity	1990	2005	2006	2007	2008	2009	2010
NO_x	**21,705**	**15,899**	**15,039**	**14,380**	**13,545**	**11,467**	**11,467**
Mobile Fossil Fuel Combustion	10,862	9,012	8,488	7,965	7,441	6,206	6,206
Stationary Fossil Fuel Combustion	10,023	5,858	5,545	5,432	5,148	4,159	4,159
Industrial Processes	591	569	553	537	520	568	568
Oil and Gas Activities	139	321	319	318	318	393	393
Incineration of Waste	82	129	121	114	106	128	128
Agricultural Burning	8	6	7	8	8	8	8
Solvent Use	1	3	4	4	4	3	3
Waste	+	2	2	2	2	2	2
CO	**129,976**	**70,791**	**67,227**	**63,613**	**59,993**	**51,431**	**51,431**
Mobile Fossil Fuel Combustion	119,360	62,692	58,972	55,253	51,533	43,355	43,355
Stationary Fossil Fuel Combustion	5,000	4,649	4,695	4,744	4,792	4,543	4,543
Industrial Processes	4,125	1,555	1,597	1,640	1,682	1,549	1,549
Incineration of Waste	978	1,403	1,412	1,421	1,430	1,403	1,403
Agricultural Burning	268	184	233	237	270	247	247
Oil and Gas Activities	302	318	319	320	322	345	345
Waste	1	7	7	7	7	7	7
Solvent Use	5	2	2	2	2	2	2
NMVOCs	**20,930**	**13,761**	**13,594**	**13,423**	**13,254**	**9,313**	**9,313**
Mobile Fossil Fuel Combustion	10,932	6,330	6,037	5,742	5,447	4,151	4,151
Solvent Use	5,216	3,851	3,846	3,839	3,834	2,583	2,583
Industrial Processes	2,422	1,997	1,933	1,869	1,804	1,322	1,322
Stationary Fossil Fuel Combustion	912	716	918	1,120	1,321	424	424
Oil and Gas Activities	554	510	510	509	509	599	599
Incineration of Waste	222	241	238	234	230	159	159
Waste	673	114	113	111	109	76	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO_2	**20,935**	**13,466**	**12,388**	**11,799**	**10,368**	**8,599**	**8,599**
Stationary Fossil Fuel Combustion	18,407	11,541	10,612	10,172	8,891	7,167	7,167
Industrial Processes	1,307	831	818	807	795	798	798
Mobile Fossil Fuel Combustion	793	889	750	611	472	455	455
Oil and Gas Activities	390	181	182	184	187	154	154

[18] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

[19] NO_x and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2008).

Incineration of Waste	38	24	24	24	23	24	24
Waste	+	1	1	1	1	1	1
Solvent Use	+	+	+	+	+	+	+
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.
NA (Not Available)
Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.5 Gg.

Key Categories

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) defines a key category as a "[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both."[20] By definition, key categories are sources or sinks that have the greatest contribution to the absolute overall level of national emissions in any of the years covered by the time series. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends of individual source and sink categories. Finally, a qualitative evaluation of key categories should be performed, in order to capture any key categories that were not identified in either of the quantitative analyses.

Figure ES-16 presents 2010 emission estimates for the key categories as defined by a level analysis (i.e., the contribution of each source or sink category to the total inventory level). The UNFCCC reporting guidelines request that key category analyses be reported at an appropriate level of disaggregation, which may lead to source and sink category names which differ from those used elsewhere in the inventory report. For more information regarding key categories, see section 1.5 and Annex 1.

Figure ES-16: 2010 Key Categories

Quality Assurance and Quality Control (QA/QC)

The United States seeks to continually improve the quality, transparency, and credibility of the Inventory of U.S. Greenhouse Gas Emissions and Sinks. To assist in these efforts, the United States implemented a systematic approach to QA/QC. While QA/QC has always been an integral part of the U.S. national system for inventory development, the procedures followed for the current inventory have been formalized in accordance with the QA/QC plan and the UNFCCC reporting guidelines.

Uncertainty Analysis of Emission Estimates

While the current U.S. emissions inventory provides a solid foundation for the development of a more detailed and comprehensive national inventory, there are uncertainties associated with the emission estimates. Some of the current estimates, such as those for CO_2 emissions from energy-related activities and cement processing, are considered to have low uncertainties. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty associated with the estimates presented. Acquiring a better understanding of the uncertainty associated with inventory estimates is an important step in helping to prioritize future work and improve the overall quality of the Inventory. Recognizing the benefit of conducting an uncertainty analysis, the UNFCCC reporting guidelines follow the recommendations of the IPCC Good Practice Guidance (IPCC 2000) and require that countries provide single estimates of uncertainty for source and sink categories.

Currently, a qualitative discussion of uncertainty is presented for all source and sink categories. Within the

[20] See Chapter 7 "Methodological Choice and Recalculation" in IPCC (2000). <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>

discussion of each emission source, specific factors affecting the uncertainty surrounding the estimates are discussed. Most sources also contain a quantitative uncertainty assessment, in accordance with UNFCCC reporting guidelines.

[BEGIN BOX]

Box ES- 3: Recalculations of Inventory Estimates

Each year, emission and sink estimates are recalculated and revised for all years in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the 2006 IPCC Guidelines (IPCC 2006), which states, “Both methodological changes and refinements over time are an essential part of improving inventory quality. It is good practice to change or refine methods” when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors.” In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data.

In each Inventory report, the results of all methodology changes and historical data updates are presented in the "Recalculations and Improvements" chapter; detailed descriptions of each recalculation are contained within each source's description contained in the report, if applicable. In general, when methodological changes have been implemented, the entire time series (in the case of the most recent inventory report, 1990 through 2010) has been recalculated to reflect the change, per the 2006 IPCC Guidelines (IPCC 2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies. References for the data are provided for additional information.

[END BOX]

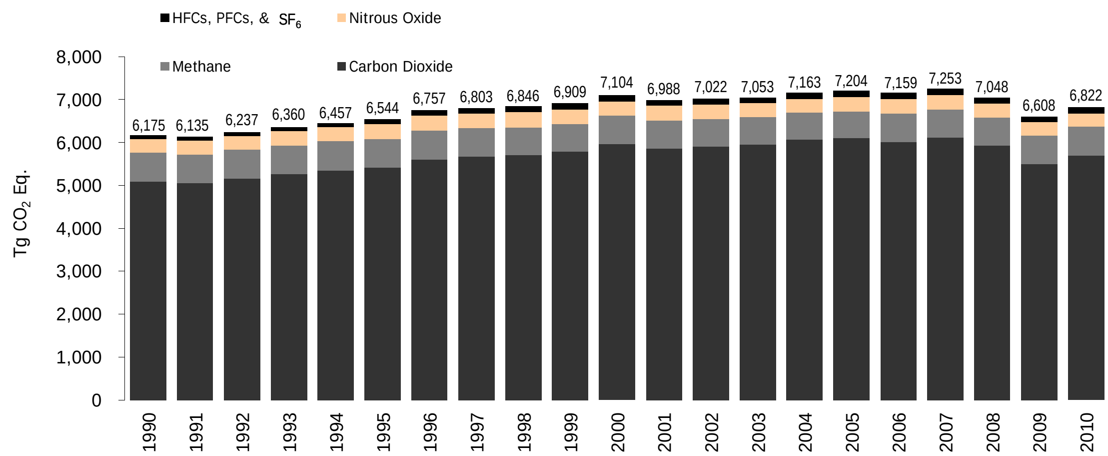


Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

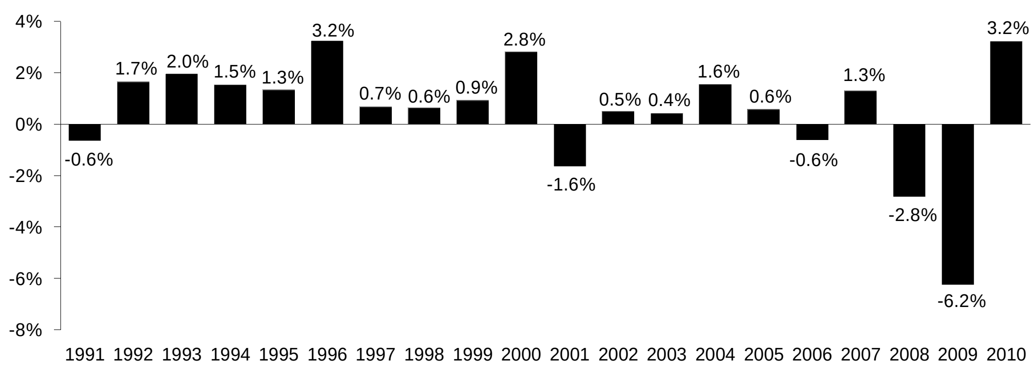


Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

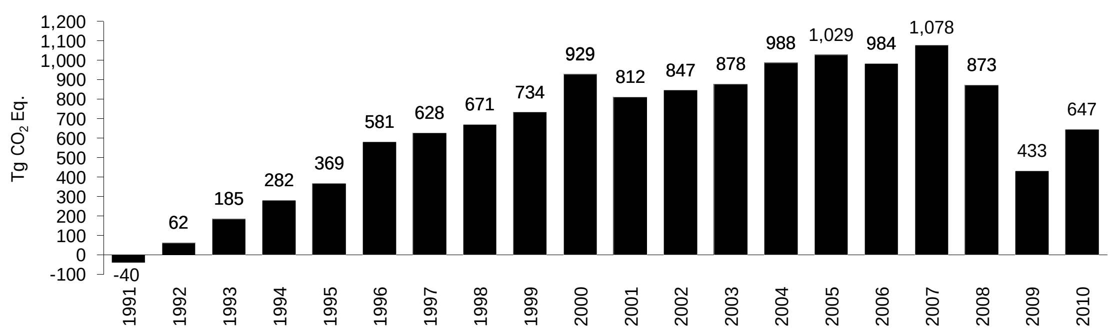


Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

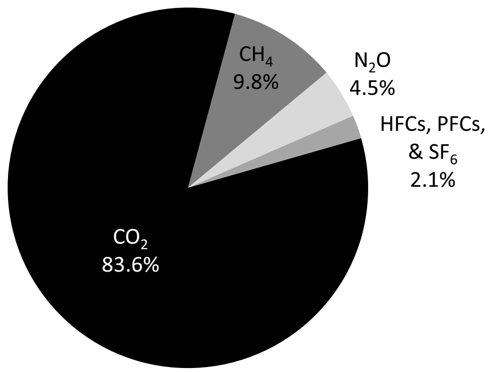


Figure ES-4: 2010 Greenhouse Gas Emissions by Gas (percents based on Tg CO_2 Eq.)

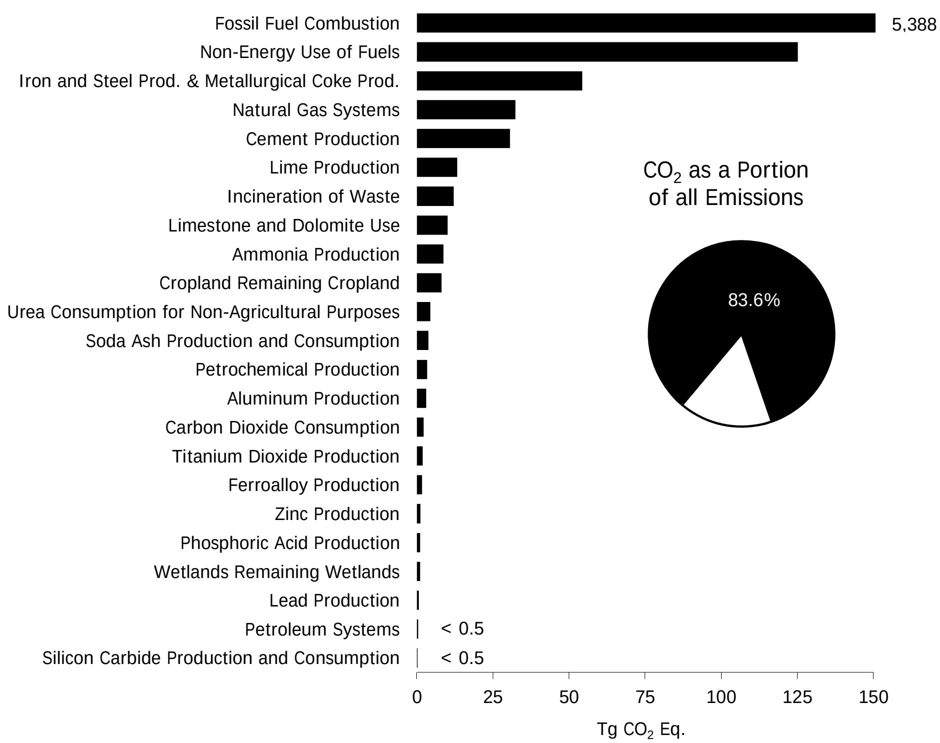


Figure ES-5: 2010 Sources of CO_2 Emissions

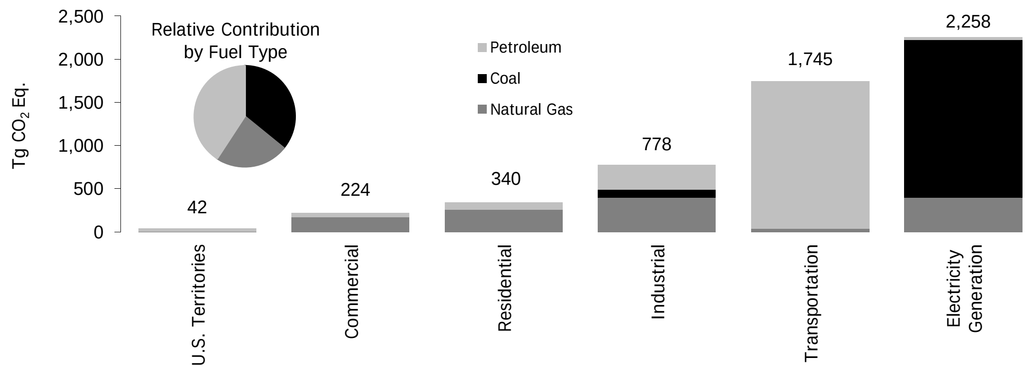


Figure ES-6: 2010 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: Electricity generation also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

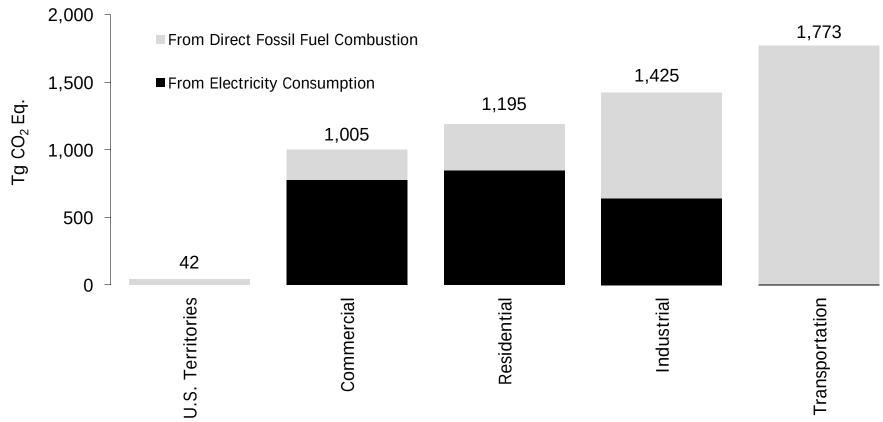


Figure ES-7: 2010 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

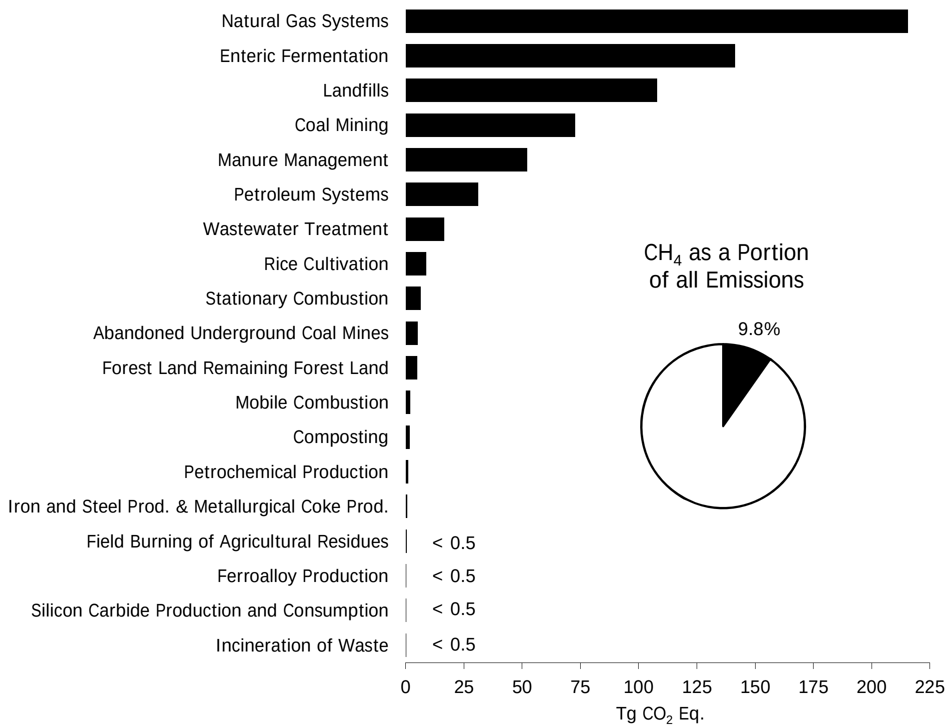


Figure ES-8: 2010 Sources of CH_4 Emissions

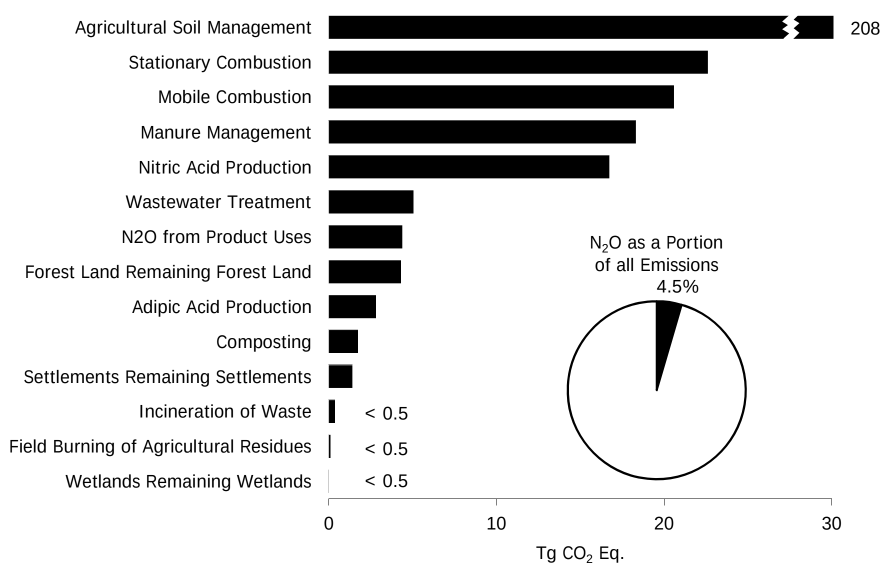


Figure ES-9: 2010 Sources of N_2O Emissions

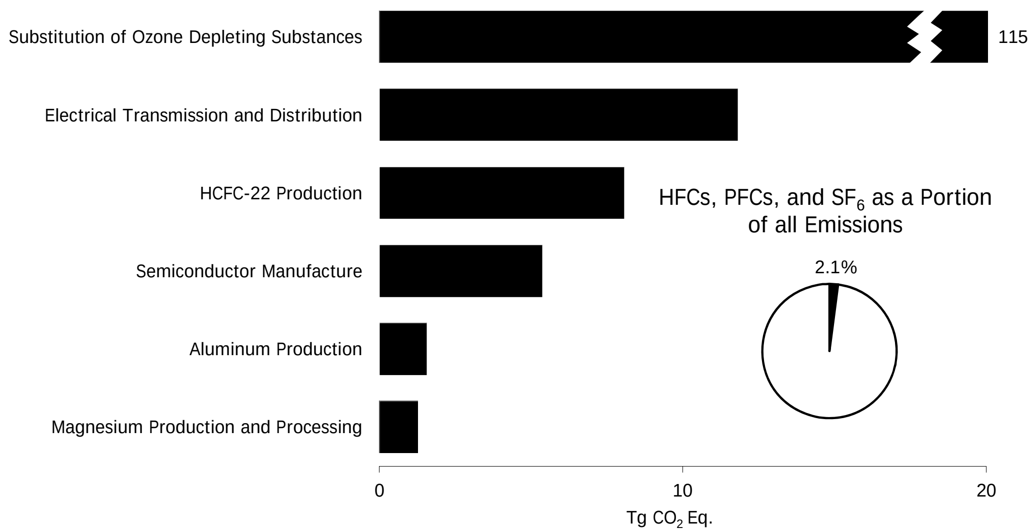
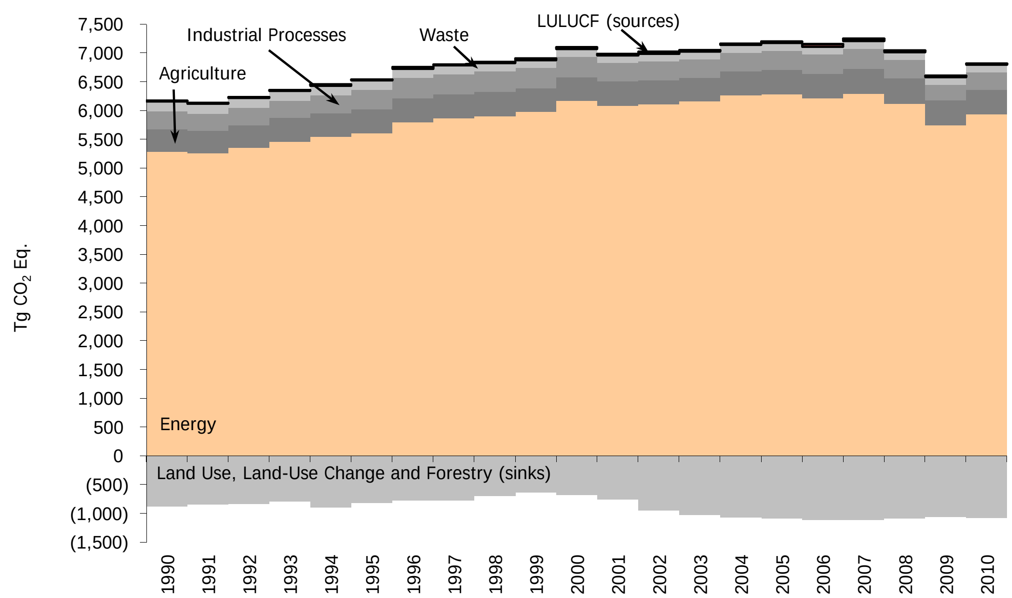


Figure ES-10: 2010 Sources of HFCs, PFCs, and SF_6 Emissions



Note: Relatively smaller amounts of GWP-weighted emissions are also emitted from the Solvent and Other Product Use sectors

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

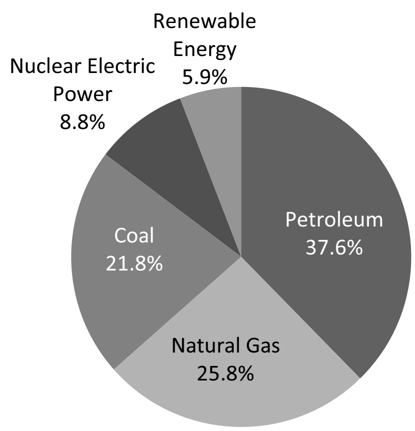


Figure ES-12: 2010 U.S. Energy Consumption by Energy Source

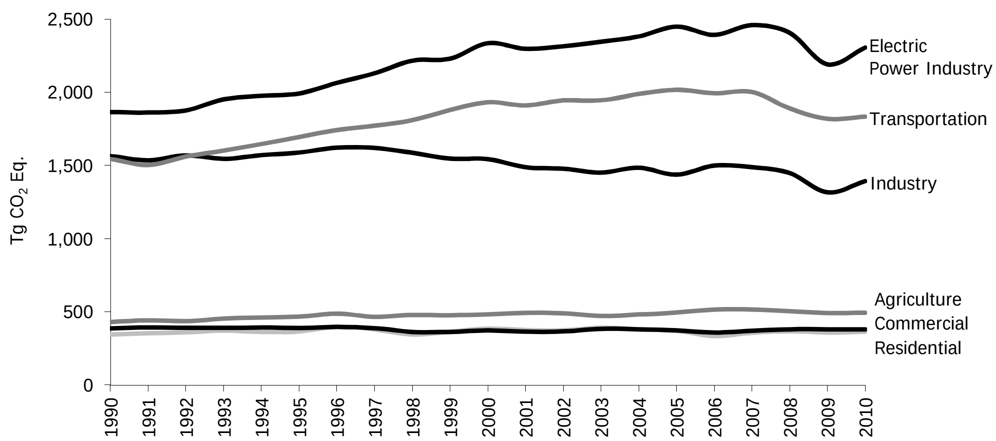


Figure ES-13: Emissions Allocated to Economic Sectors
Note: Does not include U.S. Territories.

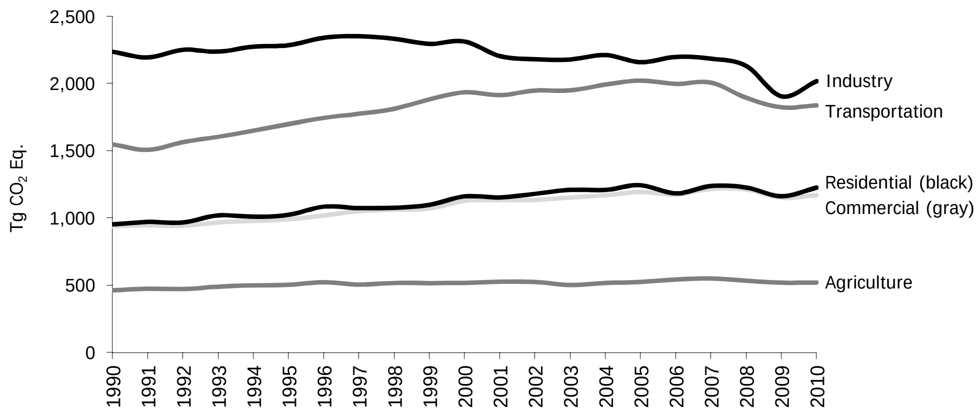


Figure ES-14: Emissions with Electricity Distributed to Economic Sectors
Note: Does not include U.S. Territories.

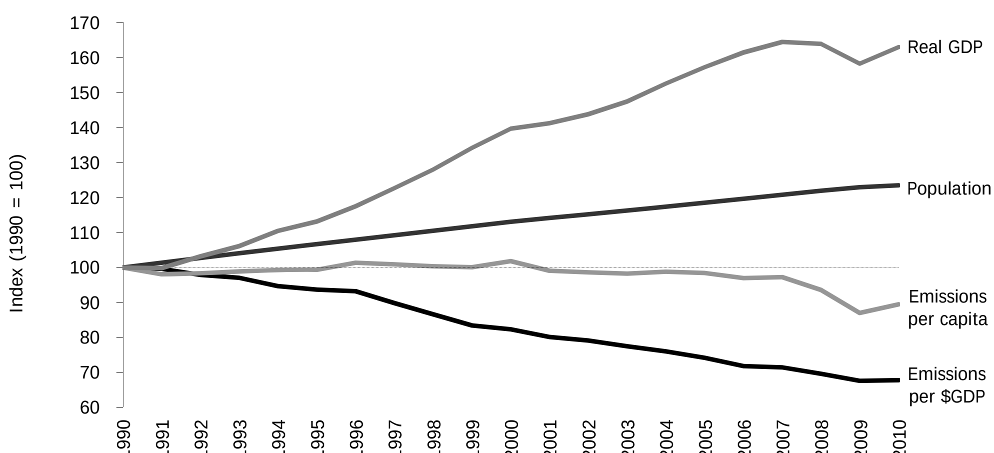


Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

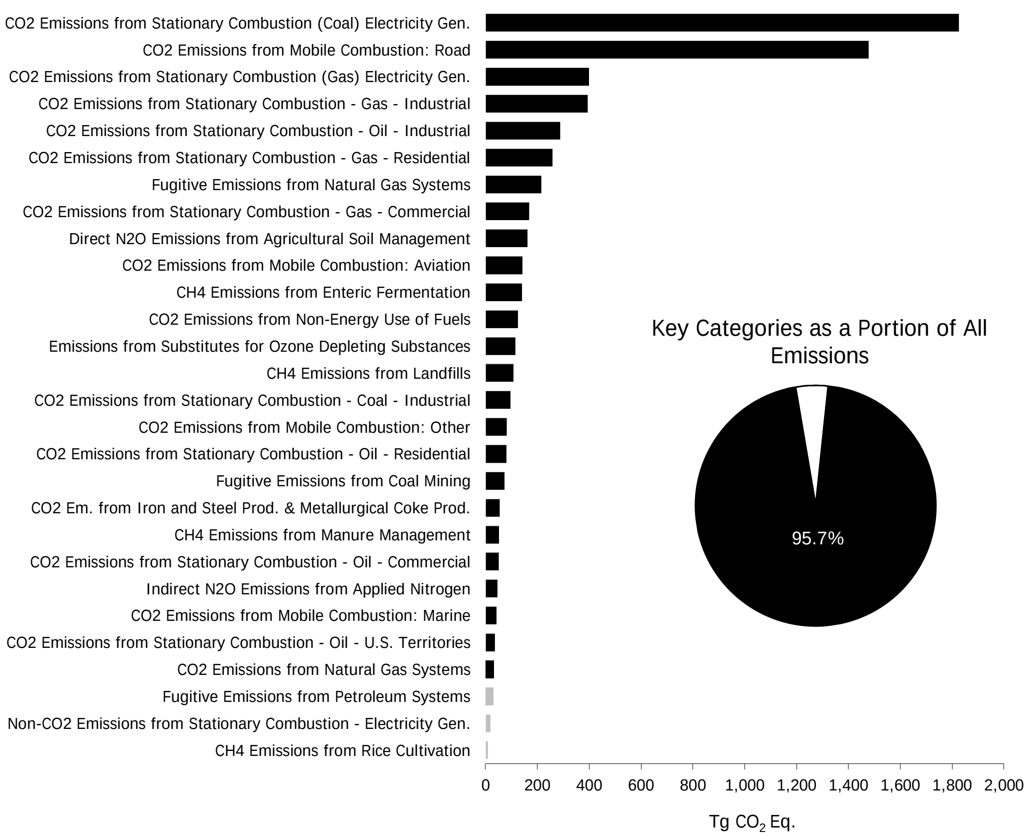


Figure ES-16: 2010 Key Categories

Notes: For a complete discussion of the key category analysis, see Annex 1.

Black bars indicate a Tier 1 level assessment key category.

Gray bars indicate a Tier 2 level assessment key category.

Hydrocarbon Emissions Characterization in the Colorado Front Range – A Pilot Study

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Abstract

The multi-species analysis of daily air samples collected at the NOAA Boulder Atmospheric Observatory (BAO) in Weld County in northeastern Colorado since 2007 shows highly correlated alkane enhancements caused by a regionally distributed mix of sources in the Denver-Julesburg Basin. To further characterize the emissions of methane and non-methane hydrocarbons (propane, n-butane, i-pentane, n-pentane and benzene) around BAO, a pilot study involving automobile-based surveys was carried out during the summer of 2008. A mix of venting emissions (leaks) of raw natural gas and flashing emissions from condensate storage tanks can explain the alkane ratios we observe in air masses impacted by oil and gas operations in northeastern Colorado. Using the WRAP Phase III inventory of total volatile organic compound (VOC) emissions from oil and gas exploration, production and processing, together with flashing and venting emission speciation profiles provided by State agencies or the oil and gas industry, we derive a range of bottom-up speciated emissions for Weld County in 2008. We use the observed ambient molar ratios and flashing and venting emissions data to calculate top-down scenarios for the amount of natural gas leaked to the atmosphere and the associated methane and non-methane emissions. Our analysis suggests that the emissions of the species we measured are most likely underestimated in current inventories and that the uncertainties attached to these estimates can be as high as a factor of two.

1) Introduction

Since 2004, the National Oceanic and Atmospheric Administration Earth System Research Laboratory (NOAA ESRL) has increased its measurement network density over North America, with continuous carbon dioxide (CO_2) and carbon monoxide (CO) measurements and daily collection of discrete air samples at a network of tall towers [Andrews et al., in preparation] and bi-weekly discrete air sampling along vertical aircraft profiles [Sweeney et al., in preparation]. Close to 60 chemical species or isotopes are measured in the discrete air samples, including long-lived greenhouse gases (GHGs) such as CO_2, methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6), tropospheric ozone precursors such as CO and several volatile organic compounds (VOCs), and stratospheric-ozone-depleting substances. The NOAA multi-species regional data set provides unique information on how important atmospheric trace gases vary in space and time over the continent, and it can be used to quantify how different processes contribute to GHG burdens and/or affect regional air quality.

In this study we focus our analysis on a very strong alkane atmospheric signature observed downwind of the Denver-Julesburg Fossil Fuel Basin (DJB) in the Colorado Northern Front Range (Figures 1 and 1S). In 2008, the DJB was home to over 20,000 active natural gas and condensate wells. Over 90% of the production in 2008 came from tight gas formations.

A few recent studies have looked at the impact of oil and gas operations on air composition at the local and regional scales in North America. Katzenstein et al. [2003] reported results of two intensive surface air discrete sampling efforts over the Anadarko

Fossil Fuel Basin in the southwestern United States in 2002. Their analysis revealed substantial regional atmospheric CH_4 and non-methane hydrocarbon (NMHC) pollution over parts of Texas, Oklahoma, and Kansas, which they attributed to emissions from the oil and gas industry operations. More recently, Schnell et al. [2009] observed very high wintertime ozone levels in the vicinity of the Jonah-Pinedale Anticline natural gas field in western Wyoming. Ryerson et al. [2003], Wert et al. [2003], de Gouw et al. [2009] and Mellqvist et al. [2009] reported elevated emissions of alkenes from petrochemical plants and refineries in the Houston area and studied their contribution to ozone formation. Simpson et al. [2010] present an extensive analysis of atmospheric mixing ratios for a long list of trace gases over oil sands mining operations in Alberta during one flight of the 2008 Arctic Research of the Composition of the Troposphere from Aircraft and Satellites campaign. Our study distinguishes itself from previous ones by the fact that it relies substantially on the analysis of daily air samples collected at a single tall-tower monitoring site between August 2007 and April 2010.

Colorado has a long history of fossil fuel extraction [Scamehorn, 2002]. Colorado natural gas production has been increasing since the 1980s, and its share of national production jumped from 3% in 2000 to 5.4% in 2008. 1.3% of the nationally produced oil in 2008 also came from Colorado, primarily from the DJB in northeastern Colorado and from the Piceance Basin in western Colorado. As of 2004, Colorado also contained 43 natural gas processing plants, representing 3.5% of the conterminous US processing capacity [EIA, 2006], and two oil refineries, located in Commerce City, in Adams County just north of Denver.

Emissions management requirements for both air quality and climate-relevant gases have led the state of Colorado to build detailed baseline emissions inventories for ozone precursors, including volatile organic compounds (VOCs), and for GHGs. Since 2004, a large fraction of the Colorado Northern Front Range, including Weld County and the Denver metropolitan area, has been in violation of the 8-hour ozone national ambient air quality standard [CDPHE, 2008a]. In December 2007, the Denver and Colorado Northern Front Range (DNFR) region was officially designated as a Federal Non-Attainment Area (NAA) for repeated violation in the summertime of the ozone National Ambient Air Quality Standard (see area encompassed by golden boundary in Figure 1). At the end of 2007, Colorado also adopted a Climate Action Plan, which sets greenhouse gas emissions reduction targets for the state [Ritter, 2007].

Methane, a strong greenhouse gas with a global warming potential (GWP) of 25 over a 100 yr time horizon [IPCC, 2007], accounts for a significant fraction of Colorado GHG emissions, estimated at 14% in 2005 ([Strait et al., 2007] and Table 1S; note that in this report, the oil and gas industry CH_4 emission estimates were calculated with the EPA State Greenhouse Gas Inventory Tool). The natural gas industry (including exploration, production, processing, transmission and distribution) is the single largest source of CH_4 in the state of Colorado (estimated at 238 Gg/yr or ktonnes/yr), followed closely by coal mining (233 Gg/yr); note that all operating surface and underground coal mines are now in western Colorado. Emission estimates for oil production operations in the state were much lower, at 9.5 Gg/yr, than those from gas production. In 2005, Weld County represented 16.5% of the state's natural gas production and 51% of the state crude oil/ natural gas condensate production (Table 2S). Scaling the state's total CH_4 emission estimates from Strait et al. [2007], rough estimates for the 2005 CH_4 source from natural gas production and processing operations and from natural gas condensate/oil production in Weld County are 19.6 Gg and 4.8 Gg, respectively. It is important to stress here that there are large uncertainties associated with these inventory-derived estimates.

Other important sources of CH_4 in the state include large open-air cattle feedlots, landfills, wastewater treatment facilities, forest fires, and agriculture waste burning, which are all difficult to quantify. 2005 state total CH_4 emissions from enteric fermentation and manure management were estimated at 143 and 48 Gg/yr, respectively [Strait et al., 2007]; this combined source is of comparable magnitude to the estimate from natural gas systems. On-road transportation is not a substantial source of methane [Nam et al., 2004].

In 2006, forty percent of the DNFR NAA's total anthropogenic VOC emissions were estimated to be due to oil and gas operations [CDPHE, 2008b]. Over the past few years, the State of Colorado has adopted more stringent VOC emission controls for oil and gas exploration and processing activities. In 2007, the Independent Petroleum Association of Mountain States (IPAMS, now Western Energy Alliance), in conjunction with the Western Regional Air Partnership (WRAP), funded a working group to build a state-of-the-knowledge process-based inventory of total VOC and NOx sources involved in oil and gas exploration, production and gathering activities for the western United State's fossil fuel basins, hereafter referred to as the WRAP Phase III effort (http://www.wrapair.org/forums/ogwg/index.html). Most of the oil and gas production in the DJB is concentrated in Weld County. Large and small condensate storage tanks in the County are estimated to be the largest VOC fossil fuel production source category (59%

and 9% respectively), followed by pneumatic devices (valve controllers) and unpermitted fugitives emissions (13% and 9% respectively). A detailed breakdown of the WRAP oil and gas source contributions is shown in Figure 2S for 2006 emissions and projected 2010 emissions [Bar-Ilan et al., 2008a,b]). The EPA NEI 2005 for Weld County, used until recently by most air quality modelers, did not include VOC sources from oil and natural gas operations (Table 3S).

Benzene (C_6H_6) is a known human carcinogen and it is one of the 188 hazardous air pollutants (HAPs) tracked by the EPA National Air Toxics Assessment (NATA). Benzene, like VOCs and CH_4, can be released at many different stages of oil and gas production and processing. Natural gas itself can contain varying amounts of aromatic hydrocarbons, including C_6H_6 [EPA, 1998]. Natural gas associated with oil production (such sources are located in several places around the DJB) usually has higher C_6H_6 levels [Burns et al., 1999] than non-associated natural gas. Glycol dehydrators used at wells and processing facilities to remove water from pumped natural gas can vent large amounts of C_6H_6 to the atmosphere when the glycol undergoes regeneration [EPA, 1998]. Condensate tanks, venting and flaring at the well-heads, compressors, processing plants, and engine exhaust are also known sources of C_6H_6 [EPA, 1998]. C_6H_6 can also be present in the liquids used for fracturing wells [EPA, 2004].

In this paper, we focus on describing and interpreting the measured variability in CH_4 and C_{3-5} alkanes observed in the Colorado Northern Front Range. We use data from daily air samples collected at a NOAA tall tower located in Weld County as well as continuous CH_4 observations and discrete targeted samples from an intensive mobile sampling campaign in the Colorado Northern Front Range. These atmospheric measurements are then used together with other emissions data sets to provide an independent view of methane and non-methane hydrocarbon emissions inventory results.

The paper is organized as follows. Section 2 describes the study design and sampling methods. Section 3 presents results from the tall tower and the Mobile Lab surveys, in particular the strong correlation among the various alkanes measured. Based on the multi-species analysis in the discrete air samples, we were able to identify two major sources of C_6H_6 in Weld County. In section 4.1 we discuss the results and in section 4.2 we compare the observed ambient molar ratios with other relevant data sets, including raw natural gas composition data from 77 gas wells in the DJB. The last discussion section, 4.3, is an attempt to shed new light on methane and VOC emission estimates from oil and gas operations in Weld County. We first describe how we derived speciated bottom-up emission estimates based on the WRAP Phase III total VOC emission inventories for counties in the DJB. We then used 1) an average ambient propane-to-methane molar ratio, 2) a set of bottom-up estimates of propane and methane flashing emissions in Weld County and 3) three different estimates of the propane-to-methane molar ratio for the raw gas leaks to build top-down methane and propane emission scenarios for venting sources in the county. We also scaled the top-down propane (C_3H_8) estimates with the observed ambient alkane ratios to calculate top-down emission estimates for n-butane (n-C_4H_{10}), i- and n-pentane (i-C_5H_{12}, n-C_5H_{12}), and benzene. We summarize our main conclusions in section 5.

2) The Front Range Emissions Study: Sampling Strategy, Instrumentation, and Sample Analysis

2.1. Overall Experimental Design

The Colorado Northern Front Range study was a pilot project to design and test a new measurement strategy to characterize GHG emissions at the regional level. The anchor of the study was a 300-m tall tower located in Weld County, 25 km east-northeast of Boulder and 35 km north of Denver, called the Boulder Atmospheric Observatory (BAO) [40.05^{o}N, 105.01^{o}W; base of tower at 1584 m above sea level] (Figure 1). The BAO is situated on the southwestern edge of the DJB. A large landfill and a wastewater treatment plant are located a few kilometers southwest of BAO. Interstate 25, a major highway going through Denver, runs in a north-south direction 2 km east of the site. Both continuous and discrete air sampling have been conducted at BAO since 2007.

To put the BAO air samples into a larger regional context and to better understand the sources that impacted the discrete air samples, we made automobile-based on-road air sampling surveys around the Colorado Northern Front Range in June and July 2008 with an instrumented "Mobile Lab" and the same discrete sampling apparatus used at all the NOAA towers and aircraft sampling sites.

2.2. BAO and other NOAA cooperative Tall Towers

The BAO tall tower has been used as a research facility of boundary layer dynamics since the 1970s [Kaimal and Gaynor, 1983]. The BAO tower was instrumented by the NOAA ESRL Global Monitoring Division (GMD) in Boulder in April 2007, with sampling by a quasi-continuous CO_2 non-dispersive infrared sensor and a CO Gas Filter Correlation instrument, both oscillating between three intake levels (22, 100 and 300 m above ground level) [Andrews et al., in preparation]. Two continuous ozone UV-absorption instruments have also been deployed to monitor ozone at the surface and at the 300-m level.

The tower is equipped to collect discrete air samples from the 300-m level using a programmable compressor package (PCP) and a programmable flasks package (PFP) described later in section 2.4. Since August 2007 one or two air samples have been taken approximately daily in glass flasks using PFPs and a PCP. The air samples are brought back to GMD for analysis on three different systems to measure a series of compounds, including methane (CH_4 , also referred to as C_1), CO, propane (C_3H_8, also referred to as C_3), n-butane (n-C_4H_{10}, nC_4), isopentane (i-C_5H_{12}, iC_5), n-pentane (n-C_5H_{12}, nC_5), acetylene (C_2H_2), benzene, chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs) and hydrofluorocarbons (HFCs). Ethane and i-butane were not measured.

In this study, we use the results from the NOAA GMD multi-species analysis of air samples collected midday at the 300-m level together with 30- second wind speed and direction measured at 300-m. 30-minute averages of the wind speed and direction prior to the collection time of each flask are used to separate samples of air masses coming from three different geographic sectors: the North and East (NE sector), where the majority of the DJB oil and gas wells are located; the South (S sector), mostly influenced by the Denver metropolitan area; and the West (W sector), with relatively cleaner air.

In 2008, NOAA and its collaborators were operating a regional air sampling network of eight towers and 18 aircraft profiling sites located across the continental US employing in-situ measurements (most towers) and flask sampling protocols (towers and aircraft sites) that were similar to those used at BAO. Median mixing ratios for several alkanes, benzene, acetylene, and carbon monoxide from BAO and a subset of five other

NOAA towers and from one aircraft site are presented in the Results (Section 3). Table 1 provides the three letter codes used for each sampling site, their locations and sampling heights. STR is located in San Francisco. WGC is located 34 km south of downtown Sacramento in California's Central Valley where agriculture is the main economic sector. Irrigated crop fields and feedlots contribute to the higher CH_4 observed at WGC. The LEF tower in northern Wisconsin is in the middle of the Chequamegon National Forest which is a mix of temperate/boreal forest and lowlands/wetlands [Werner et al., 2003]. Air samples from NWF (surface elevation 3050m), in the Colorado Rocky Mountains, mostly reflect relatively unpolluted air from the free troposphere. The 457m tall Texas tower (WKT) is located between Dallas/Fort Worth and Austin. It often samples air masses from the surrounding metropolitan areas. In summer especially, it also detects air masses with cleaner background levels arriving from the Gulf of Mexico. The SGP NOAA aircraft sampling site [Sweeney et al., in preparation; http://www.esrl.noaa.gov/gmd/ccgg/aircraft/] in northern Oklahoma is also used in the comparison study. At each aircraft site, twelve discrete air samples are collected at specified altitudes on a weekly or biweekly basis. Oklahoma is the fourth largest state for natural gas production in the USA [EIA, 2008] and one would expect to observe signatures of oil and gas drilling operations at both SGP and BAO. Additional information on the tower and aircraft programs is available at http://www.esrl.noaa.gov/gmd/ccgg/. Median summer mixing ratios for several alkanes, C_2H_2, C_6H_6 and CO are presented in the Results section.

2.3. Mobile Sampling

Two mobile sampling strategies were employed during this study. The first, the Mobile Lab, consisted of a fast response CO_2 and CH_4 analyzer (Picarro, Inc.), a CO gas-filter correlation instrument from Thermo Environmental, Inc., an O_3 UV-absorption analyzer from 2B Technologies and a Global Positioning System (GPS) unit. All were installed onboard a vehicle. A set of 3 parallel inlets attached to a rack on top of the vehicle brought in outside air from a few meters above the ground to the instruments. Another simpler sampling strategy was to drive around and collect flask samples at predetermined locations in the Front Range region. A summary of the on-road surveys is given in Table 2.

The Mobile Lab's Picarro Envirosense $CO_2/CH_4/H_2O$ analyzer (model G1301, unit CFADS09) employs Wavelength-Scanned Cavity Ring-Down Spectroscopy (WS-CRDS), a time-based measurement utilizing a near-infrared laser to measure a spectral signature of the molecule. CO_2, CH_4, and water vapor were measured at a 5-second sampling rate (0.2 Hz), with a standard deviation of 0.09 ppm in CO_2 and 0.7 ppb for CH_4. The sample was not dried prior to analysis, and the CO_2 and CH_4 mole fractions were corrected for water vapor after the experiment based on laboratory tests. For water mole fractions between 1% and 2.5%, the relative magnitude of the CH_4 correction was quasi-linear, with values between 1 and 2.6%. CO_2 and CH_4 mole fractions were assigned against a reference gas tied to the relevant World Meteorological Organization (WMO) calibration scale. Total measurement uncertainties were 0.1 ppm for CO_2 and 2 ppb for CH_4 [Sweeney et al., in preparation]. The CO and ozone data from the Mobile Lab are not discussed here. GPS data were also collected in the Mobile Lab at 1 Hz, to allow data from the continuous analyzers to be merged with the location of the vehicle.

The excursions with the flask sampler (PFP) focused on characterizing the concentrations of trace gases in Boulder (June 4 and 11, 2008), the northeastern Front Range (June 19), Denver (July 1) and around oil and gas wells and feedlots in Weld County south of Greeley (July 14) (see Table 2). Up to 24 sampling locations away from direct vehicle emissions were chosen before each drive.

Each Mobile Lab drive lasted from four to six hours, after a ~30 min warm-up on the NOAA campus for the continuous analyzer before switching to battery mode. The first two Mobile Lab drives, which did not include discrete air sampling, were surveys around Denver (July 9) and between Boulder and Greeley (July 15). The last two drives with the Mobile Lab (July 25 and 31) combined in-situ measurements with discrete flask sampling to target emissions from specific sources: the quasi-real-time display of the data from the continuous CO_2/CH_4 analyzer was used to collect targeted flask samples at strong CH_4 point sources in the vicinity of BAO. Discrete air samples were always collected upwind of the surveying vehicle and when possible away from major road traffic.

2.4. Chemical Analyses of Flask Samples

Discrete air samples were collected at BAO and during the road surveys with a two-component collection apparatus. One (PCP) includes pumps and batteries, along with an onboard microprocessor to control air sampling. Air was drawn through Teflon tubing attached to an expandable 3-m long fishing pole. The second package (PFP) contained a sampling manifold and twelve cylindrical, 0.7L, glass flasks of flow-through design, fitted with Teflon O-ring on both stopcocks. Before deployment, manifold and flasks were leak-checked then flushed and pressurized to ~1.4 atm with synthetic dry zero-air containing approximately 330 ppm of CO_2 and no detectable CH_4. During sampling, the manifold and flasks were flushed sequentially, at ~5 L min^{-1} for about 1 min and 10 L min^{-1} for about 3 minutes respectively, before the flasks were pressurized to 2.7 atm. Upon returning to the NOAA lab, the PFP manifold was leak-checked and meta-data recorded by the PFP during the flushing and sampling procedures were read to verify the integrity of each air sample collected. In case of detected inadequate flushing or filling, the affected air sample is not analyzed.

Samples collected in flasks were analyzed for close to 60 compounds by NOAA GMD (http://www.esrl.noaa.gov/gmd/ccgg/aircraft/analysis.html). In this paper, we focus on eight species: 5 alkanes (CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12}) as well as CO, C_2H_2 and C_6H_6. CH_4 and CO in each flask were first quantified on one of two nearly identical automated analytical systems (MAGICC 1 & 2). These systems consist of a custom-made gas inlet system, gas-specific analyzers, and system-control software. Our gas inlet systems use a series of stream selection valves to select an air sample or standard gas, pass it through a trap for drying maintained at ~-80°C, and then to an analyzer.

CH_4 was measured by gas chromatography (GC) with flame ionization detection (±1.2 ppb = average repeatability determined as 1 s.d. of ~20 aliquots of natural air measured from a cylinder) [Dlugokencky et al., 1994]. We use the following abbreviations for measured mole fractions: ppm = μmol mol^{-1}, ppb = nmol mol^{-1}, and ppt = pmol mol^{-1}. CO was measured directly by resonance fluorescence at ~150 nm (±0.2 ppb) [Gerbig et al., 1999; Novelli et al., 1998]. All measurements are reported as dry air mole fractions relative to internally consistent calibration scales maintained at NOAA (http://www.esrl.noaa.gov/gmd/ccl/scales.html).

Gas chromatography/mass spectrometric (GC/MS) measurements were also performed on ~200 mL aliquots taken from the flask samples and pre-concentrated with a cryogenic trap at near liquid nitrogen temperatures [Montzka et al., 1993]. Analytes desorbed at ~110^{o}C were then separated by a temperature-programmed GC column (combination 25 m x 0.25 mm DB5 and 30 m x 0.25 mm Gaspro), followed by detection with mass spectrometry by monitoring compound-specific ion mass-to-charge ratios. Flask sample responses were calibrated versus whole air working reference gases which, in turn, are calibrated with respect to gravimetric primary standards (NOAA scales: benzene on NOAA-2006 and all other hydrocarbons (besides CH_4) on NOAA-2008). We used a provisional calibration for n-butane based on a diluted Scott Specialty Gas standard. Total uncertainties for analyses from the GC/MS reported here are <5% (accuracy) for all species except n-C_4H_{10} and C_2H_2, for which the total uncertainty at the time of this study was of the order of 15-20%. Measurement precision as repeatability is generally less than 2% for compounds present at mixing ratios above 10 ppt.

To access the storage stability of the compounds of interest in the PFPs, we conducted storage tests of typically 30 days duration, which is greater than the actual storage time of the samples used in this study. Results for C_2H_2 and C_3H_8 show no statistically significant enhancement or degradation with respect to our "control" (the original test gas tank results) within our analytical uncertainty. For the remaining species, enhancements or losses average less than 3% for the 30 day tests. More information on the quality control of the flask analysis data is available at http://www.esrl.noaa.gov/gmd/ccgg/aircraft/qc.html.

The flask samples were first sent to the GC/MS instrument for hydrocarbons, CFCs, and HFCs before being analyzed for major GHGs. This first step was meant to screen highly polluted samples that could potentially damage the greenhouse gas MAGICC analysis line with concentrations well above "background" levels. The time interval between flask collection and flask analysis spanned between 1 to 11 days for the GC/MS analysis and 3 to 12 days for MAGICC analysis.

3) Results

3.1 BAO tall tower: long-term sampling platform for regional emissions

3.1.1 Comparing BAO with other sampling sites in the US

Air samples collected at BAO tower have a distinct chemical signature (Figure 2), showing enhanced levels of most alkanes (C_3H_8, nC_4H_{10}, iC_5H_{12} and nC_5H_{12}) in comparison to results from other NOAA cooperative tall towers (see summary of site locations in Table 1 and data time series in Figure 1S). The midday summer time median mixing ratios for C_3H_8 and n-C_4H_{10} at BAO were at least 6 times higher than those observed at most other tall tower sites. For i-C_5H_{12} and n-C_5H_{12}, the summertime median mixing ratios at BAO were at least 3 times higher than at the other tall towers.

In Figure 2, we show nighttime measurements at the Niwot Ridge Forest tower (NWF) located at a high elevation site on the eastern slopes of the Rocky Mountains, 50 km west of BAO. During the summer nighttime, downslope flow brings clean air to the tower [Roberts et al., 1984]. The median summer mixing ratios at NWF for all the species shown in Figure 2 are much lower than at BAO, as would be expected given the site's remote location.

Similarly to BAO, the northern Oklahoma aircraft site, SGP, exhibits high alkane levels in the boundary layer and the highest methane summer median mixing ratio of all sites shown in Figure 2 (1889 ppb at SGP vs. 1867 ppb at BAO). As for BAO, SGP is located in an oil- and gas-producing region. Oklahoma, the fourth largest state in terms of natural gas production in the US, has a much denser network of interstate and intrastate natural gas pipelines compared to Colorado. Katzenstein et al. [2003] documented the spatial extent of alkane plumes around the gas fields of the Anadarko Basin in Texas, Oklahoma, and Kansas during two sampling intensives. The authors estimated that methane emissions from the oil and gas industry in that entire region could be as high as 4-6 Tg CH_4/yr, which is 13-20% of the US total methane emission estimate for year 2005 reported in the latest EPA US GHG Inventory [EPA, 2011a].

Enhancements of CH_4 at BAO are not as striking in comparison to other sites. CH_4 is a long-lived gas destroyed predominantly by its reaction with OH radicals. CH_4 has a background level that varies depending on the location and season [Dlugokencky et al., 1994], making it more difficult to interpret differences in median summer CH_4 mixing ratios at the suite of towers. Since we do not have continuous measurements of CH_4 at any of the towers except WGC, we cannot clearly separate CH_4 enhancements from background variability in samples with levels between 1800 and 1900 ppb if we only look at CH_4 mixing ratios by themselves (see more on this in the next section).

3.1.2 Influence of different sources at BAO

3.1.2.1. Median mixing ratios in the three wind sectors

To better separate the various sources influencing air sampled at BAO, Figure 3 shows the observed median mixing ratios of several species as a function of prevailing wind direction. For this calculation, we only used samples for which the associated 30-minute average wind speed (prior to collection time) was larger than 2.5 m/s. We separated the data into three wind sectors: NE, including winds from the north, northeast and east (wind directions between 345^o and 120^o); S, including south winds (120^o to 240^o); and W, including winds from the west (240^o to 345^o).

For the NE sector, we can further separate summer (June to August) and winter (November to April) data. For the other two wind sectors, only the winter months have enough data points. The species shown in Figure 3 have different photochemical lifetimes [Parrish et al., 1998], and all are shorter-lived in the summer season. This fact, combined with enhanced vertical mixing in the summer, leads to lower mixing ratios in summer than in winter.

Air masses from the NE sector pass over the oil and gas wells in the DJB and exhibit large alkane enhancements. In winter, median mole fractions of C_3-C_5 alkanes are 8 to 11 times higher in air samples from the NE compared to the samples from the W sector, while the median CH_4 value is 76 ppb higher. The NE wind sector also shows the highest median values of C_6H_6, but not CO and C_2H_2.

C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers in air samples from the NE wind sector are much higher than in air samples coming from the Denver metropolitan area in the South wind sector. Besides being influenced by Denver, southern air masses may pass over two operating landfills, the Commerce City oil refineries, and some oil and gas wells (Figure 1). The S sector BAO CO and C_2H_2 mixing ratios are higher than for the other wind sectors, consistent with the higher density of vehicular emission sources [Harley et al., 1992; Warneke et al., 2007; Baker et al., 2008] south of BAO. There are also occasional spikes in CFC-11 and CFC-12 mixing ratios in the S sector (not shown). These are most probably due to leaks from CFC-containing items in the landfills. Air parcels at BAO coming from the east pass over Interstate Highway 25, which could explain some of the high mole fractions observed for vehicle combustion tracers such as CO, C_2H_2, and C_6H_6 in the NE sector data (see more discussion on C_6H_6 and CO in section 4.4 & Figure 4).

The W wind sector has the lowest median mole fractions for all anthropogenic tracers, consistent with a lower density of emission sources west of BAO compared to the other wind sectors. However, the S and W wind sectors do have some data points with high alkane values, and these data will be discussed further below.

3.1.2.2. Strong alkane source signature

To detect if the air sampled at BAO has specific chemical signatures from various sources, we looked at correlation plots for the species shown in Figure 3. Table 3 summarizes the statistics for various tracer correlations for the three different wind sectors. Figure 4 (left column) shows correlation plots of some of these BAO species for summer data in the NE wind sector.

Even though BAO data from the NE winds show the largest alkane mixing ratios (Figure 3), all three sectors exhibit strong correlations between C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers (Table 3). The r^2 values for the correlations between C_3H_8 and n- C_4H_{10} or the C_5H_{12} isomers are over 0.9 for the NE and W sectors. CH_4 is also well correlated with C_3H_8 in the NE wind sector for both seasons. For the NE wind sector BAO summertime data, a min/max range for the C_3H_8/CH_4 slope is 0.099 to 0.109 ppb/ppb.

The tight correlations between the alkanes suggest a common source located in the vicinity of BAO. Since large alkane enhancements are more frequent in the NE wind sector, this common source probably has larger emissions north and east of the tower. This NE wind sector encompasses Interstate Highway 25 and most of the DJB oil and gas wells. The C_3-C_5 alkane mole fractions do not always correlate well with combustion tracers such as C_2H_2 and CO for the BAO NE wind sector ($C_{3\text{-}5}$/CO and $C_{3\text{-}5}/C_2H_2$: $r^2 <$ 0.3 for 50 summer samples; $C_{3\text{-}5}$/CO: r^2 <0.4 and $C_{3\text{-}5}/C_2H_2$: r^2 ~0.6 for 115 winter samples). These results indicate that the source responsible for the elevated alkanes at BAO is not the major source of CO or C_2H_2, which argues against vehicle combustion exhaust as being responsible. Northeastern Colorado is mostly rural with no big cities. The only operating oil refineries in Colorado are in the northern part of the Denver metropolitan area, south of BAO. The main industrial operations in the northeastern Front Range are oil and natural gas exploration and production and natural gas processing and transmission. We therefore hypothesize here that the oil and gas operations in the DJB, as noted earlier in Section 2, are a potentially substantial source of alkanes in the region.

3.1.2.3. At least two sources of benzene in BAO vicinity

The median winter C_6H_6 mixing ratio at BAO is higher for the NE wind sector compared to the South wind sector, which comprises the Denver metropolitan area. The C_6H_6-to-CO winter correlation is highest for the S and W wind sectors BAO samples (r^2=0.85 and 0.83 respectively) compared to the NE wind sector data (r^2=0.69). The C_6H_6-to-CO correlation slope is substantially higher for the NE wind sector data compared to the other two wind sectors, suggesting that there may be a source of benzene in the NE that is not a significant source of CO. The C_6H_6-to-C_2H_2 correlation slope is slightly higher for the NE wind sector data compared to the other two wind sectors. C_6H_6 in the BAO data from the NE wind sector correlates more strongly with C_3H_8 than with CO. The C_6H_6-to-C_3H_8 summer correlation slope for the NE wind sector is 10.1 ±1.2 ppt/ppb (r^2=0.67).

For the S and W wind sectors BAO data, the C_6H_6-to-C_2H_2 (0.27 - 0.32 ppt/ppt) and C_6H_6-to-CO (1.57 - 1.81 ppt/ppb) slopes are larger than observed emissions ratios for the Boston/New York City area in 2004: 0.171 ppt/ppt for C_6H_6-to-C_2H_2 ratio and 0.617 ppt/ppb for C_6H_6-to-CO ratio [Warneke et al., 2007]. Baker et al. [2008] report an atmospheric molar C_6H_6-to-CO ratio of 0.9 ppt/ppb for Denver in summer 2004, which is in between the Boston/NYC emissions ratio value reported by Warneke et al. [2007] and the BAO S and W wind sectors correlation slopes.

The analysis of the BAO C_6H_6 data suggests the existence of at least two distinct C_6H_6 sources in the vicinity of BAO: an urban source related mainly to mobile emissions, and a common source of alkanes and C_6H_6 concentrated in northeastern Colorado. We discuss C_6H_6 correlations and sources in more detail in section 4.4.

3.2. On-road surveys: tracking point and area source chemical signatures

Road surveys with flask sampling and the Mobile Lab with the fast-response CH_4 analyzer were carried out in June-July 2008 (Table 2). The extensive chemical analysis of air samples collected in the Front Range provides a snapshot of a broader chemical composition of the regional boundary layer during the time of the study. The Mobile Lab surveys around the Front Range using the in situ CH_4 analyzer allowed us to detect large-scale plumes with long-lasting enhancements of CH_4 mixing ratios as well as small-scale plumes associated with local CH_4 point sources. In the last two Mobile Lab surveys (surveys 8 and 9), we combined the monitoring of the continuous CH_4 analyzer with targeted flask sampling, using the CH_4 data to decide when to collect flask samples in and out of plumes.

The regional background CH_4 mixing ratio at the surface (interpreted here as the lowest methane level sustained for ~10 minutes or more) was between 1800 ppb and 1840 ppb for most surveys. Some of the highest "instantaneous" CH_4 mixing ratios measured during the Mobile Lab surveys were: 3166 ppb at a wastewater treatment plant, 2329 ppb at a landfill, 2825 ppb at a feedlot near Dacono, over 7000 ppb close to a feedlot waste pond near Greeley, and 4709 ppb at a large natural gas processing and propane plant in Fort Lupton (Figure 1).

The analysis of the summer 2008 intensive data suggests that regional scale mixing ratio enhancements of CH_4 and other alkanes are not rare events in the Colorado Northern Front Range airshed. Their occurrence and extent depends on both emissions and surface wind conditions, which are quite variable and difficult to predict in this area. During the Mobile Lab road surveys, the high-frequency measurements of CO_2 and CH_4 did not exhibit any correlation. Unlike CO_2, the CH_4 enhancements were not related to on-road emissions. Below we present two examples of regional enhancements of CH_4 observed during the Front Range Mobile Lab surveys.

3.2.1. Survey 9: $C_{3\text{-}5}$ alkane levels follow large-scale changes in methane

Figure 5 shows a time series of the continuous CH_4 mixing ratio data and alkane mixing ratios measured in twelve flask samples collected during the Front Range Mobile Lab survey on 31 July 2008 (flasks #1 to 12, sampled sequentially as shown in Figure 6). The wind direction on that day was from the ENE or E at the NCAR Foothills Lab and BAO tower. The Mobile Lab left the NOAA campus in Boulder around 11:40 am and measured increasing CH_4 levels going east towards the BAO tower (Figure 6). An air sample was collected close to the peak of the CH_4 broad enhancement centered around 11:55 am. The CH_4 mixing ratio then decreased over the next 25 minutes and reached a local minimum close to 1875 ppb. The CH_4 level stayed around 1875 ppb for over one hour and then decreased again, more slowly this time, to ~ 1830 ppb over the next two hours.

Flasks # 1 to 3 were collected before, at the peak, and immediately after the broad CH_4 feature between 11:40 and 12:15. Flasks # 4 & 5 were sampled close to a wastewater treatment plant and flasks # 7 to 8 were sampled in a landfill. The in situ measurements showed that CH_4 was still elevated above background as these samples were collected. After a 90-minute stop at BAO to recharge the Mobile Lab UPS batteries, flasks # 9 to 11 were collected in a corn field while the in situ measurements showed lower CH_4 levels. The last flask sample was collected on the NOAA campus just before 17:00 MDT, about 5.5 hours after the first flask sample was collected. The flask samples were always collected upwind of the Mobile Lab car exhaust.

Sharp spikes in the continuous CH_4 data reflect local point sources (wastewater treatment plant, landfill). The highly variable signals in both the continuous and discrete CH_4 close to these sources are driven by the spatial heterogeneity of the CH_4 emissions and variations in wind speed and direction. Broader enhancements in the continuous CH_4 data reflect larger (regional) plumes. The last flask (#12) sampled at NOAA has much higher levels of combustion tracers (CO, C_2H_2, C_6H_6) than the other samples.

Figure 7 shows correlation plots for C_3H_8 versus CH_4 and n-C_4H_{10} versus C_3H_8 in the 12 flasks taken on 31 July. Air samples not directly influenced by identified point sources (flasks #1-3, 6-7, 9-12) show a very strong correlation between the various measured alkanes. Using the data from the air samples not directly influenced by identified point sources (flasks #1-3, 6-7, 9-12), we derive a C_3H_8-to-CH_4 (C_3/C_1) mixing ratio slope of 0.097± 0.005 ppb/ppb (Figure 7A). This slope is very similar to the one observed for the summertime NE wind sector data at BAO (0.104± 0.005; Table 3). Three air samples collected downwind of the waste water treatment plant and the landfill (flasks # 4-5 and 8) are off the C_3H_8-to-CH_4 correlation line and have higher CH_4 than air samples collected nearby but not under the influence of these local CH_4 sources (flasks 3 and 6). Flask # 8 also has elevated CFC-11 (310 ppt) compared to the other samples collected that day (< 255 ppt), probably related to leaks from old appliances buried in the landfill.

The C_3-C_5 alkane mixing ratios in samples collected on 31 July are tightly correlated for flasks # 1 to 11 with $r^2 > 0.95$ (Figure 7B). As concluded for the BAO alkane mixing ratio enhancements earlier, this tight correlation suggests that the non-methane alkanes measured during the surveys are coming from the same source types. The nC_4/C_3 correlation slope on 31 July (0.47 ppb/ppb; flasks # 1-11) is similar to the summer slope in the BAO NE samples (0.45 ppb/ppb), while the 31 July iC_5/C_3 and nC_5/C_3 slopes are slightly higher (0.17 and 0.17 ppb/ppb, respectively) than for BAO (0.14 and 0.15 ppb/ppb, respectively).

3.2.2. Survey 6: Alkane enhancements in the Denver-Julesburg oil and gas production zone and cattle feedlot contributions to methane

The flask-sampling-only mobile survey on 14 July 2008 focused on the agricultural and oil and gas drilling region south of Greeley. Eleven of the twelve air samples collected on 14 July were taken over the Denver-Julesburg Basin (flasks# 2-12 in Figure 3S in Supplementary Material). Figure 8A shows a correlation plot of C_3H_8 versus CH_4 mixing ratios in these air samples. Flasks collected NE of BAO and not near feedlots (# 4, 6-8, and 10-12) fall on a line: y=0.114(x-1830) (r^2=0.99). This slope and the correlation slope calculated for the BAO NE wind sector data are indistinguishable (within the 1-σ uncertainties in the slopes). Four samples collected in the vicinity of four different cattle feedlots (flasks # 2, 3, 5, and 9) exhibit a lower C_3H_8-to-CH_4 correlation slope (0.083 ppb/ppb, r^2=0.93). The r^2 for the C_3H_8-to-CH_4 correlation using all the flasks is 0.91.

The n-C_4H_{10} versus C_3H_8 correlation plot and its slope, along with the n-C_4H_{10}–to-C_3H_8 and C_5H_{12}–to-C_3H_8 correlation slopes for air samples not collected downwind of feedlots are shown in Figure 8B. The r^2 for the n-C_4H_{10}-to-C_3H_8 correlation using all the flasks is 0.98, which is slightly higher than the r^2 for the C_3H_8-to-CH_4 correlation using all flasks (0.91). The r^2 for the i-C_5H_{12}-to-n-C_4H_{10} and n-C_5H_{12}-to-n-C_4H_{10} correlations using all the flasks are 0.96 ppb/ppb and 0.99 ppb/ppb, respectively. These results suggest that cattle feedlots have no substantial impact on n-C_4H_{10} and the C_5H_{12} levels.

The strong correlation observed between the various alkane mixing ratios for air samples not collected downwind of feedlots once again suggests that a common source contributes to most of the observed alkanes enhancements. It is possible that some of the C_3H_8 enhancements seen near the feedlots are due to leaks of propane fuel used for farm operations [Ronald Klusman, personal communication]. Two flask samples were collected downwind of a cattle feedlot near Dacono during Mobile Lab survey #8, on 25 July 2008. The analysis of these samples revealed large CH_4 enhancements (1946 and 2335 ppb), but no enhancement in C_3H_8 (~ 1ppb), n-C_4H_{10} (<300ppt), the C_5H_{12} (< 130ppt) or C_6H_6 (< 30ppt).

For survey #6, the n-C_4H_{10}-to-C_3H_8 correlation slope (0.56 ppb/ppb) is 16% higher than the summer slope observed at BAO for the NE wind sector data, while the 14 July i-C_5H_{12}-to-C_3H_8 and n-C_5H_{12}-to-C_3H_8 correlation slopes (0.24 and 0.23 ppb/ppb, respectively) are 76% and 53% higher, respectively, than the summer NE BAO data. These slopes are higher than for flasks from survey #9. The difference in the C_5/C_3 slopes between the various Mobile Lab surveys data and the BAO NE summer data may reflect the spatial variability in the alkane source molar composition.

3.2.3. Benzene source signatures

To look at the C_6H_6 correlations with other tracers, the 88 Mobile Lab flask samples have been divided into two subsets, none of which includes the three samples collected downwind of the natural gas and propane processing plant near Dacono, CO. In the summer, the lifetimes of C_6H_6 and C_3H_8 at 800 mbar and 40^{o}N are close to 3 or 4 days and the lifetime of CO is about 10 days [Finlayson-Pitts and Pitts, 2000; Spivakovsky et al., 2000].

The first subset of 39 samples has C_3H_8 mixing ratios smaller than 3 ppb and it includes flasks collected mostly during surveys #2, 3 and 4. For this subset influenced mostly by urban and mobile emissions, C_6H_6 correlates well with CO (slope=1.82 ppt/ppb, r^2=0.89) and C_2H_2 (slope=0.37 ppt/ppt, r^2=0.75) but not with C_3H_8 (r^2<0.3). The C_6H_6-to-CO correlation slope for this subset is similar to the correlation slopes for the BAO S and W wind sector winter samples.

The second subset of 46 samples corresponds to flasks with a C_3H_8 mixing ratio larger than 3ppb. These flasks were collected mostly during surveys #1, 6, 8 and 9. For this second subset influenced mostly by emissions from the DJB, C_6H_6 correlates well with C_3H_8 (slope=17.9 ppt/ppb, r^2=0.95) but not with CO or C_2H_2 (r^2<0.3). The C_6H_6-to-

C_3H_8 slope for these samples is almost twice as big as the slope calculated for the BAO NE wind sector data (10.1 ppt/ppb) (Table 3).

4) Discussion

4.1. Comparing the alkane enhancements in the BAO and Mobile Lab data sets

In the previous section we showed two examples of enhanced alkanes in northeast Colorado using mobile sampling (surveys 6 and 9 on 14 and 31 July 2008, respectively). With lifetimes against OH removal on the order of 3.5, 1.7 and 1.0 days in the summer at 40^{o}N [Finlayson-Pitts and Pitts, 2000; Spivakovsky et al., 2000] respectively, C_3H_8, n-C_4H_{10} and the C_5H_{12} isomers do not accumulate over the continent. Instead their atmospheric mixing ratios and the slopes of correlations between different alkanes reflect mostly local or regional sources within a few days of atmospheric transport.

The source responsible for the alkane enhancements observed at BAO and in multiple surveys during the Front Range Study appears to be located in the northeastern part of the Front Range region within the Denver-Julesburg Basin, so we call it the DJB source. The small differences in alkane correlation slopes for the BAO and Mobile Lab samples likely reflect differences in the emitted alkane molar ratios across this distributed source, as well as the mix of chemical ages for the air samples collected at a variety of locations and on different days.

In Table 3 and Figure 4, we compare the alkane correlation slopes in the Mobile Lab flask data set with the correlation slopes in the BAO data set. To calculate the DJB source C_3H_8-to-CH_4 correlation slope from the Mobile Lab data set, we have removed air samples collected downwind of feedlots, the wastewater treatment plant, and the natural gas and propane processing plant (Figure 1). The Mobile Lab flasks C_3H_8-to-CH_4 correlation slope is 0.095±0.007 ppb/ppb (R^2=0.76, 77 samples), similar to the slope calculated for the BAO NE wind sector data. Samples collected downwind of the natural gas processing plant exhibit variable chemical signatures, reflecting a complex mix of contributions from leaks of gas and combustion exhaust from flaring units and compressor engines.

To calculate the DJB source n-C_4H_{10}-to-C_3H_8, i-C_5H_{12}-to-C_3H_8 and n-C_5H_{12}-to-C_3H_8 correlation slopes from the Mobile Lab data set, we have removed the three air samples collected downwind of the natural gas and propane processing plant (Figure 1). The C_4/C_3, i-C_5/C_3 and n-C_5/C_3 correlation slopes in the Mobile Lab data are 0.49, 0.19 and 0.19 ppb/ppb, respectively (r^2> 0.8, 85 samples). The i-C_5/C_3 and n-C_5/C_3 correlation slopes are 40% and 30% higher, respectively, than the BAO NE sector summer slopes. If we remove the 11 data points from survey #6 samples collected in the middle of the DJB, the C_5H_{12}-to-C_3H_8 ratios are only 15% higher than calculated for the NE sector at BAO.

High correlations among various alkanes were reported in this region by Goldan et al. [1995]. In that study, hourly air samples were analyzed with an in-situ gas chromatograph deployed on a mesa at the western edge of Boulder for two weeks in

February 1991. CH_4 was not measured during that study. The correlation coefficient (r^2) between C_3H_8, n-C_4H_{10}, and the C_5H_{12} isomers was around 0.86, with a clear minimum slope for the abundance ratios (see Figure 4 in Goldan et al. [1995]). The authors proposed that the C_4-C_6 alkanes shared one common source with propane (called the "C_3 source" in the next section and in Figure 9), with additional emissions contributing to some C_4-C_6 alkane enhancements.

4.2. Comparing the Front Range observed alkane signatures with VOC emissions profiles for oil and gas operations in the Denver-Julesburg Basin

In this section we compare the alkane ratios calculated from the BAO NE wind sector and the Mobile Lab samples to emissions profiles from the DJB oil and gas exploration and production sector. Most of these profiles were provided by the WRAP Phase III inventory team, who developed total VOC and NOx emission inventories for oil and gas production and processing operation in the DJB for 2006 [Bar-Ilan et al., 2008a]. Emissions and activity data were extrapolated by the WRAP Phase III inventory team to derive emission estimates for 2010 based on projected production numbers and on state and federal emissions control regulations put in place in early 2008 for oil and gas permitted activities in the DNFR NAA [Bar-Ilan et al., 2008b]. The VOCs included in the inventories are: C_3H_8, i,n-C_4H_{10}, i,n-C_5H_{12} and higher alkanes, C_6H_6, toluene, ethyl-benzene, xylenes and 224-trimethylpentane. The WRAP Phase III inventories for 2006 and 2010 were only provided as total VOC and NOx emitted at the county level for all the counties in the Colorado part of the DJB. The emission estimates are based on various activity data (including the number of new wells (spuds), the total number of wells, estimates of oil, condensate and gas production, and equipment counts) and measured/reported or estimated VOC speciation profiles for the different source categories. Supplementary Figure 2S and Bar-Ilan et al. [2008a,b] present more details on how the inventory emission estimates are derived.

We focus primarily on flashing and venting sources here, since the WRAP Phase III inventory indicates that these two sources are responsible for 95% of the total VOC emissions from oil and gas exploration and production operations in Weld County and in the NAA [Bar-Ilan et al., 2008a,b] (see Figure 2S). In 2006, all the oil produced in the DJB was from condensate wells. Condensate tanks at well pads or processing plants store a mostly-liquid mix of hydrocarbons and aromatics separated from the lighter gases in the raw natural gas. Flash losses or emissions happen for example when the liquid condensate is exposed to decreasing atmospheric pressure: gases dissolved in the liquid are released and some of the heavier compounds may be entrained with these gases. Flashing emissions from condensate storage tanks are the largest source of VOCs from oil and gas operations in the DJB. In the DNFR NAA, operators of large condensate tanks have to control and report emission estimates to the Colorado Department of Public Health and the Environment (CDPHE). In 2006 and 2010 flashing emissions represented 69% and 65% respectively of the total VOC source from oil and gas exploration, production and processing operations, for the nine counties in the NAA (see supplementary Figure 2S and Bar-Ilan et al. [2008a] for more details on how the estimates are derived).

Venting emissions are related to loss of raw natural gas when a new oil or gas well is drilled or when an existing well is vented (blowdown), repaired or restimulated (recompletion). Equipment at active well sites (e.g. well head, glycol dehydrators and pumps) or in the midstream network of compressors and pipelines gathering the raw natural gas can also leak significant amounts of natural gas. In the WRAP Phase III inventory, venting emissions represented 27% and 21% respectively of the total VOC estimated source from the NAA oil and gas operations in 2006 and 2010 ([Bar-Ilan et al., 2008a,b], Figure 2S).

The molar compositions of venting and flashing emissions are quite different (see supplementary Figure 4S). Emissions from flash losses are enriched in C_{2+} alkanes compared to the raw natural gas emissions. To convert the total VOC bottom-up source into speciated emission ratio estimates, we use molar ratio profiles for both flashing and venting emissions reported in three data sets:

- Bar-Ilan et al. [2008a]: mean venting profile used for the 2006 DJB inventory, also called the "Venting-WRAP" profile;
- Colorado Oil and Gas Conservation Commission [COGCC, 2007]: composition of 77 samples of raw natural gas collected at different wells in the Greater Wattenberg Area in December 2006, also called "Venting-GWA" profiles. Note that C_6H_6 was not reported in this data set;
- Colorado Department of Public Health and the Environment (CDPHE, personal communication): flashing emissions profiles based on condensate composition data from 16 different storage tanks in the DJB and EPA TANK2.0 (flashing emissions model) runs.

Figure 9 shows a comparison of the alkane molar ratios for the raw natural gas and flash emissions data sets with the correlation slopes derived for the Mobile Lab 2008 samples and for air samples collected at BAO in the summer months only (between August 2007 and April 2010) for the NE wind sector (cf. Table 4S to get the plotted values). The alkane correlation slopes observed at BAO and across the Northern Front Range with the Mobile Lab are all within the range of ratios reported for flashing and/or venting emissions. The C_{3-5} alkane ratios for both flashing and venting emissions are too similar for their atmospheric ratios to be useful in distinguishing between the two source processes. The ambient C_3H_8-to-CH_4 and n-C_4H_{10}-to-CH_4 molar ratios are lower than what could be expected from condensate tank flashing emissions alone, indicating that most of the CH_4 observed came from the venting of raw natural gas. In the next section, we will describe how we derive bottom-up emission estimates for CH_4 and C_3H_8 as well as three top-down emissions scenarios consistent with the observed atmospheric slopes.

Figure 9 also shows the correlation slopes calculated by Goldan et al. [1995] for the 1991 Boulder study. These slopes compare very well with the BAO and Mobile Lab results and the oil and gas venting and flashing emissions ratios. Goldan et al. [1995] compared the measured C_4/C_3 and C_5/C_3 ratios for the Boulder C_3 source (see definition in Section 4.1) with the ratios reported in the locally distributed pipeline-quality natural gas for February 1991, and concluded that the common C_3H_8 and higher alkane source was not linked with the local distribution system of processed natural gas. However, the composition of the raw natural gas at the extraction well is quite different from the purified pipeline-quality natural gas distributed to end-users. Processed pipeline-quality natural gas delivered throughout the USA is almost pure CH_4 [Gas Research Institute, 1992]. Since Goldan et al. [1995] did not measure CH_4 in their 1991 study, they could not determine if the atmospheric C_{3+}/C_1 alkane ratios were higher than expected in processed natural gas.

4.3. Estimation of the alkane source in Weld County

Bottom-up speciated emission estimates

In this section, we derive bottom-up and top-down estimates of alkane emissions from the DJB source for Weld County. We have averaged the 2006 and 2010 WRAP Phase III total VOC emissions data [Bar-Ilan et al., 2008ab] to get bottom-up estimates for the year 2008, resulting in 41.3 Gg/yr for flashing emissions and 16.8 Gg/yr for venting emissions. There are no uncertainty estimates provided in the WRAP Phase III inventory. 2006 total VOC flashing emission estimates in Weld County are based on reported emissions for controlled large condensate tanks (34.8 Gg/yr) and calculated emissions for uncontrolled small condensate tanks (5.4 Gg/yr) (see [Bar-Ilan et al., 2008] for more details). Uncertainties attached to these estimates may be due to inaccurate emissions factors (number of pounds of VOC flashed per tons of condensate produced) and/or inaccurate estimate of the effectiveness of emission control systems.

The WRAP Phase III total VOC emission from venting sources for Weld County was calculated by averaging industry estimates of the volume of natural gas vented or leaked to the atmosphere by various processes shown in Figure 2S (well blowdown, well completion, pneumatic devices…). A basin-wide average of gas composition analyses provided by oil and gas producers was then used to compute a bottom-up estimate of the total mass of VOC vented to the atmosphere by oil and gas exploration, production and processing operations. Uncertainties attached to the venting source can be related to uncertainties in leak rates or intensity of out-gassing events, as well to the variability in the composition of raw natural gas, none of which were quantitatively taken into account in the WRAP Phase III inventory.

Next we describe the calculations, summarized in Figure 5S, to derive bottom-up estimates of venting and flashing emissions for the various trace gases we measured using information from the WRAP Phase III inventory and the COGCC GWA raw natural gas composition data set (Table 4 and supplementary Figure 6S). From the total annual vented VOC source and the average vented emission profile provided by Bar-Ilan et al. [2008a] (Table 2S), we derived an estimate of the volume of natural gas that we assumed is vented to the atmosphere by the oil and gas production and processing operations in Weld County. Following Bar-Ilan et al. inventory data and assumptions [2008a], we used the weight fraction of total VOC in the vented gas (18.74%), the molar mass of the vented gas (21.5g/mol) and standard pressure and temperature with the ideal gas law to assume that 1 mole of raw natural gas occupies a volume 22.4 L (as was done in the WRAP Phase III inventory). The total volume of vented gas we calculate for Weld County in 2008 is 3.36 billion cubic feet (Bcf), or the equivalent of 1.68% of the total natural gas produced in the county in 2008 (202.1 Bcf). We then use the estimate of the volume of vented gas and the molar composition profiles for the 77 raw natural gas samples reported in the COGCC GWA study to compute average, minimum, and maximum emissions for CH_4, each of the C_{3-5} alkanes we measured, and C_6H_6. Using this procedure, 2008 Weld County average venting CH_4 and C_3H_8 bottom-up source estimates are 53.1 Gg/yr and 7.8 Gg/yr, respectively (Table 4).

For flashing emissions, we distributed the WRAP 2008 total annual VOC source estimate (41.3 Gg/yr) using the modeled flash loss composition profiles for 16 different condensate tanks provided by the CDPHE. Average CH_4 and C_3H_8 emissions as well as the minimum and maximum estimates are reported in Table 4. The 2008 average flashing CH_4 and C_3H_8 bottom-up emission estimates are 11.2 Gg/yr and 18.3 Gg/yr, respectively (Table 4). The total flashing + venting CH_4 and C_3H_8 bottom-up estimates range from 46 to 86 Gg/yr and from 15 to 52 Gg/yr, respectively.

Top-Down emissions scenarios

Finally, we use our atmospheric measurements to bring new independent constraints for the estimation of venting and flashing emissions in Weld County in 2008. The exercise consists in calculating three top-down venting emission scenarios for CH_4 and C_3H_8 (x_m, x_p: mass of methane and propane vented respectively) consistent with a mean observed CH_4-to-C_3H_8 atmospheric molar ratio of 10 ppb/ppb (Table 4) in the DJB. We assume, as done earlier in the bottom-up calculations, that the observed C_3H_8-to-CH_4 ratio in the DJB results from a combination of flashing and venting emissions. The bottom-up information used here is (1) the set of speciated flashing emissions derived earlier for the 16 condensate tanks provided by CDPHE for CH_4 and C_3H_8 $(y_m, y_p)_{\mathrm{tank}=1,16}$, and (2) three scenarios for the basin-average raw (vented) natural gas CH_4-to-C_3H_8 molar ratio, denoted $v_{m/p}$. The three values used for basin-average vented gas CH_4-to-C_3H_8 molar ratio are: 18.75, which is the WRAP Phase III inventory assumption (scenario 1);

15.43, which is the median of the molar ratios for the COGCC GWA 77 gas samples (scenario 2); and 24.83, which is the mean of the molar ratios for the COGCC GWA 77 gas samples (scenario 3). For each vented gas profile scenario, we use the set of 16 flash emission estimates to calculate an ensemble of venting emission estimates for CH_4 (x_m) and C_3H_8 (x_p) following the two equations below.

The first equation formalizes the assumption for CH_4-to-C_3H_8 molar ratio of the vented raw natural gas, with M_m (16g/mol) and M_p (44g/mol) being the molar masses of CH_4 and C_3H_8 respectively.:

$$v_{m/p} = \frac{M_p}{M_m} \times \frac{x_m}{x_p} \qquad (1)$$

In the second equation, the mean observed atmospheric CH_4-to-C_3H_8 molar ratio ($a_{m/p}$=10 ppb/ppb) constrains the overall ratio of methane versus propane emitted by both flashing and venting sources. Therefore, for each set of 16 bottom-up flashed emission estimates (y_m, y_p), we have:

$$\frac{M_p\left(x_m + y_m\right)}{M_m\left(x_p + y_p\right)} = a_{m/p} \qquad (2)$$

The analytical solutions to this set of equations are given by:

$$\begin{aligned} x_p &= \frac{1}{\left(v_{m/p} - a_{m/p}\right)} \times \left(a_{m/p} \times y_p - \frac{M_p}{M_m} y_m \right) \\ x_m &= v_{m/p} \times \frac{M_m}{M_p} \times x_p \end{aligned} \qquad (3)$$

The average, minimum and maximum venting emission estimates, x_m and x_p, are reported for the three vented gas profile scenarios in Table 4 and Figure 10.

The first goal of this top-down estimation exercise is to highlight the many assumptions required to build the bottom-up and top-down emission estimates. The choices made for the WRAP Phase III inventory or our top-down calculations are all reasonable, and the uncertainty attached to the values chosen (if available) should be propagated to calculate total uncertainty estimates for the final emission products. When the error propagation is done conservatively, the emission uncertainty is close to a factor of 2 for both CH_4 and C_3H_8. This number is much higher than the 30% uncertainty reported by the EPA for the 2009 national CH_4 source estimate from natural gas systems [EPA, 2011c].

The scenario 1 mean top-down vented CH_4 source (118.4 Gg/yr) is twice as large as the bottom-up estimate of 53.1 Gg/yr (Table 4). If we assume that 77% (by volume) of the raw gas is CH_4, an average estimate of 118.4 Gg/yr of CH_4 vented would mean that the equivalent of 4% of the 2008 natural gas gross production in Weld County was vented. It is important to note that the top-down scenarios cover a large range (67-229 Gg/yr), corresponding to between 2.3% and 7.7% of the annual production being lost to the atmosphere through venting (Table 4). The lowest estimate is, however, larger than what we derived from the WRAP Phase III bottom-up inventory (1.68%). If instead of using the EIA [EIA, 2004] convention for the molar volume of gas (23.6 L/mol), we used the standard molar volume used by WRAP (22.4 L/mol), our top-down calculations of the volume of gas vented would be 5% lower than reported in Table 4.

Emissions for the other alkanes measured are all derived from the C3H8 total sources scaled with the atmospheric molar ratios observed in the BAO NE summer samples and the Mobile Lab samples. Figure 10 shows a comparison of the bottom-up estimates and the top-down emission scenarios (mean of scenario 1 and overall minimum and maximum of the three scenarios).

The main result of this exercise is that for each of the three top-down total emissions scenarios, the mean estimates for CH_4, n-C_4H_{10} and the C_5H_{12} isomers are at least 60% higher than the bottom-up mean estimates. The minimum top-down emissions scenarios are lower than (in the case of C_3H_8) or higher than (for CH_4, nC_4H_{10}, i-C_5H_{12}, n-C_5H_{12}) the bottom-up mean estimates.

To put the top-down CH_4 source estimate from oil and gas exploration, production and processing operations in perspective, we compare it with an estimate of the passive "geological" CH_4 flux over the entire DJB. Klusman and Jakel [1998] reported an average flux of 0.57 mg CH_4/m^2/day in the DJB due to natural microseepage of light alkanes. Multiplied by a rough upper boundary estimate of the DJB surface area (Figure 1), the estimated annual natural flux is 0.66 Gg CH_4 /yr, or less than 1% of the top-down venting source estimated for active exploration and production of natural gas in Weld County.

4.4. Benzene sources in the Northern Front Range

On-road vehicles are estimated to be the largest source of C_6H_6 in the US [EPA, 2009a]. Emissions from on-road and off-road vehicles and from large point sources (including chemical plants and refineries) have been regulated by the EPA for over thirty years [Fortin et al., 2005; Harley et al., 2006]. When motor vehicle combustion dominates emissions, such as in the BAO S and W wind sectors, C_6H_6 correlates well with CO and C_2H_2.

Crude oil and natural gas production and processing emitted an estimated 8333 tonnes of benzene nationally in 2005, which represented 2% of the national total C_6H_6

source [EPA, 2009a]. C_6H_6 and C_3H_8 have similar photochemical lifetimes (~ 3-4 days in the summer), so the observed atmospheric ratios we report in Table 3 should be close to their emission ratio if they are emitted by a common source. The strong correlation between C_6H_6 and C_3H_8 (Figure 4, Table 3) for the BAO NE wind sector and in the DJB Mobile Lab air samples suggests that oil and gas operations could also be a non-negligible source of C_6H_6 in the Northern Colorado Front Range.

The C_6H_6-to-C_3H_8 molar ratios in the flash losses from 16 condensate tanks simulated with the EPA TANK model are between 0.4 to 5.6 ppt/ppb. The C_6H_6-to-C_3H_8 molar ratio reported for vented emissions in the WRAP Phase III inventory is 5.3 ppt/ppb, based on regionally averaged raw gas speciation profiles provided by local companies [Bar-Ilan et al., 2008a] (only an average profile was provided, other data is proprietary). These emission ratios are at least a factor of two lower than the atmospheric ratios measured in the Front Range air samples influenced by the DJB source (Table 3).

If we use the mean C_3H_8 emission estimate for scenario 1 described in Section 4.3 (35.7 Gg/yr), together with the C_6H_6-to-C_3H_8 correlation slope for the summer BAO NE wind sector data and that from the Mobile Lab samples (10.1 ppt/ppb and 17.9 ppt/ppb respectively), we derive a C_6H_6 emission estimate for the DJB source in Weld County in 2008 of 639 tonnes/yr (min/max range: 478/883 tonnes/yr) and 1145 tonnes/yr (min/max range: 847/1564 tonnes/yr), respectively. As expected, these numbers are much higher than what we derived for the bottom-up flashing and venting emissions (total of 139 tonnes/yr, min/max range of 49-229 tonnes/yr). For comparison, C_6H_6 emissions from facilities in Colorado reporting to the US EPA for the Toxics Release Inventory amounted to a total of 3.9 tonnes in 2008 [EPA, 2009b] and on–road emissions in Weld

County were estimated at 95.4 tonnes/yr in 2008 [CDPHE, personal communication]. Based on our analysis, oil and gas operations in the DJB could be the largest source of C_6H_6 in Weld County.

More measurements are needed to further evaluate the various potential sources associated with oil and gas operations (for example, glycol dehydrators and condensate tank flash emissions). The past two iterations of the C_6H_6 emissions inventory developed by the State of Colorado for the National Emissions Inventory and compiled by the EPA do not show much consistency from one year to another. The 2008 and 2005 NEI reported very different C_6H_6 emission estimates for condensate tanks in Weld County (21.5 Mg/yr versus 1120 Mg/yr, respectively; see also Table 3S). Estimates in the 2008 NEI are much closer to estimates provided by CDPHE (personal communication) for 2008 (21.3 Mg/yr), suggesting the 2005 NEI estimate may be flawed, even though it is in the range of our top-down estimation. We conclude that the current level of understanding of emissions of C_6H_6 from oil and gas operations cannot explain the top-down range of estimates we derive in our study, suggesting that, once again, more field measurements are needed to understand and quantify oil and gas operation sources.

5) Conclusion

This study provides a regional overview of the processes impacting ambient alkane and benzene levels in northeastern Colorado in the late 2000s. We report atmospheric observations collected by two sampling platforms: a 300-m tall tower located in the SW corner of Weld County (samples from 2007 to 2010), and road surveys by a Mobile Lab equipped with a continuous methane analyzer and discrete canister sampling (June-July 2008). The analysis of the tower data filtered by wind sector reveals a strong alkane and benzene signature in air masses coming from northeastern Colorado, where the main activity producing these compounds is related to oil and gas operations over the Denver–Julesburg Fossil Fuel Basin. Using the Mobile Lab platform, we sampled air directly downwind of different methane sources (oil and gas wells, a landfill, feedlots, and a waste water treatment plant) and collected targeted air samples in and out of plumes. The tall tower and Mobile Lab data both revealed a common source for air masses with enhanced alkanes. In the data from both platforms, the alkane mixing ratios were strongly correlated, with slight variations in the correlation slopes depending on the location and day of sampling. The alkanes did not correlate with combustion tracers such as carbon monoxide and acetylene. We hypothesize that the observed alkanes were emitted by the same source located over the Denver-Julesburg Basin, "the DJB source".

The second part of the study brings in information on VOC emissions from oil and gas activities in the DJB from the detailed bottom-up WRAP Phase III inventory [Bar Ilan et al., 2008a,b]. We have used the total VOC emission inventory and associated emissions data for DJB condensate and gas production and processing operations to calculate annual emission estimates for CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12} and C_6H_6 in Weld County. The main findings are summarized below:

- The emissions profiles for flashing and venting losses are in good agreement with the atmospheric alkane enhancement ratios observed during this study and by Goldan et al. [1995] in Boulder in 1991. This is consistent with the hypothesis that the observed alkane atmospheric signature is due to oil and gas operations in the DJB.

- The three top-down emission scenarios for oil and gas operations in Weld County in 2008 give a rather large range of potential emissions for CH_4 (71.6-251.9 Gg/yr) and the higher alkanes. Except for propane, the lowest top-down alkanes emission estimates are always larger than the inventory-based mean estimate we derived based on the WRAP Phase III inventory data and the COGCC GWA raw gas composition data set.
- There are notable inconsistencies between our results and state and national regulatory inventories. In 2008 gas wells in Weld County represented 15% of the state's production. Based on our top-down analysis, Weld County methane emissions from oil and gas production and processing represent at least 30% of the state total methane source from natural gas systems derived by Strait et al. [2007] using the EPA State Inventory Tool. The methane source from natural gas systems in Colorado is most likely underestimated by at least a factor of two. Oil and gas operations are the largest source of alkanes in Weld County. They were included as a source of "total VOC" in the 2008 EPA NEI for Weld County but not in the 2005 NEI.
- There are at least two main sources of C_6H_6 in the region: one related to combustion processes, which also emit CO and C_2H_2 (engines and mobile vehicles), and one related to the DJB alkane source. The C_6H_6 source we derived based on flashing and venting VOC emissions in the WRAP inventory (143 Mg/yr) most likely underestimates the actual total source of C_6H_6 from oil and gas

operations. Our top-down source estimates for C_6H_6 from oil and gas operations in Weld County cover a large range: 385-2056 Mg/yr. Again, the lowest figure is much higher than reported in the 2008 CDPHE inventory for Weld County oil and gas total point sources (61.8 Mg/yr).

- Samples collected at the BAO tall tower or while driving around the Front Range reflect the emissions from a complex mix of sources distributed over a large area. Using a multi-species analysis including both climate and air quality relevant gases, we can start unraveling the contributions of different source types. Daily multi-species measurements from the NOAA collaborative network of tall towers in the US provide a unique opportunity to understand source chemical signatures in different airsheds and how these emissions may change over time.
- More targeted multi-species well-calibrated atmospheric measurements are needed to evaluate current and future bottom-up inventory emissions calculations for the fossil fuel energy sector and to reduce uncertainties on absolute flux estimates for climate and air quality relevant trace gases.

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List of Figures

Figure 1: Map of the study area centered on the Boulder Atmospheric Observatory (BAO), located 25 km east-northeast of Boulder. Overlaid on this map are the locations of active oil and gas wells (light purple dots) as of April 2008 (data courtesy of SkyTruth, http://blog.skytruth.org/2008/06/colorado-all-natural-gas-and-oil-wells.html, based on COGCC well data). Also shown are the locations of landmarks used in the study, including selected point sources (NGP Plant = natural gas processing plant, WWT Plant = Lafayette wastewater treatment plant).

Figure 2: Observed median mixing ratios for several species measured in air samples taken at various sites at midday during June-August (2007-2010). The sites are described in Table 1. Only nighttime samples are shown for NWF to capture background air with predominantly down-slope winds. Notice the different units with all columns and the different scaling applied to methane, propane and n-butane.

Figure 3: Summertime and wintertime median mixing ratios of several species measured in air samples from the 300-meter level at the BAO tower for three wind sectors: North and East (NE) where the density of gas drilling operations is highest, South (S) with Denver 35 km away, and West (W) with mostly clean air. The time span of the data is from August 2007 to April 2010. Summer includes data from June to August and winter includes data from November to April. Due to the small number of data points (<15), we do not show summer values for the S and W wind sectors. Data outside of the 11am-3pm local time window were not used. Notice the different scales used for methane, propane and n-butane. The minimum number of data points used for each wind sector is: NE summer 33, NE winter 89, S winter 65 and W winter 111.

Figure 4: Correlation plots for various species measured in the BAO summertime NE wind sector flask samples (left column) and summer 2008 Mobile Lab (right column) samples. Data at BAO were filtered to keep only midday air samples collected between June and August over the time period spanning August 2007 to August 2009. See also Table 3.

Figure 5: (Top panel) Time series of the continuous methane measurements from Mobile Lab Survey # 9 on July 31, 2008. Also shown are the mixing ratio data for the 12 flask samples collected during the road survey. The GC/MS had a faulty high energy dynode cable when these samples were analyzed, resulting in more noisy data for the alkanes and the CFCs ($\sigma < 10\%$ instead of 5%). However, the amplitudes of the $C_{3\text{-}5}$ alkane signals are much larger than the noise here. The methane mixing ratio scale is shown on the left hand vertical axis. For all other alkanes, refer to the right hand vertical axis. (Bottom panel) Time series of wind directions at the NCAR Foothills and Mesa Laboratories in Boulder (see Figure 6 for locations) and from the 300-m level at the BAO on July 31, 2008.

Figure 6: Continuous methane observations (colored squares) and flask (circles) samples collected during the July 31, 2008 Mobile Lab Survey #9 in Boulder and Weld County. The size of the symbols (and the symbol color for the continuous methane data) represents the mixing ratio of continuous/flask methane (squares, green circles) and flask propane (blue circles). The labels indicate the flask sample number (also shown in the time series in Figure 5). NCAR = National Center for Atmospheric Research, FL = NCAR Foothills Laboratory, ML = NCAR Mesa Laboratory, WWT Plant = Lafayette wastewater treatment plant.

Figure 7: A) Propane versus methane mixing ratios for air samples collected during Survey #9 on July 31, 2008. B) n-butane versus propane mixing ratios in the same air samples. The black line in plot A shows the correlation line for samples not impacted by local sources of methane (all flasks except #4, 5, 8, and 12). The black line in plot B shows the correlation line for all samples except flask 12. The flask sample number is shown next to each data point. The twelve samples were filled sequentially (see Figure 6).

Figure 8: A) Propane versus methane mixing ratios for air samples collected during Survey #6 on July 14, 2008. B) n-butane versus propane mixing ratios in the same air samples. The black line in plot A shows the correlation line for samples not impacted by local sources of methane (all flasks except 1-3, 5, and 9). The black line in plot B shows the correlation line for samples not impacted by local sources of propane.

Figure 9: Alkane correlation slopes in air samples collected at BAO (NE wind sector, summer samples only, blue) and over the Denver-Julesburg Basin (red) during the Front Range Study (June-July 2008) are compared with VOC emissions molar ratios for flashing (green) and venting (grey) sources used by Bar-Ilan et al. [2008a] for the DJB WRAP Phase III emissions inventory. The error bars indicate the min and max values for the flashing emissions molar ratios. Also shown are the mean, min and max molar ratios derived from the composition analysis of gas samples collected in 2006 at 77 different gas wells in the Great Wattenberg Area (yellow, [Colorado Oil and Gas Conservation Commission, 2007]). Goldan et al. [1995] data are from a two week measurement campaign in the Foothills, west of Boulder, in February 1991 (light purple). Goldan et al. identified a "local" propane source (lower limit for correlation slope) with clear C_{4-5} alkane ratios to propane (dark propane, see also text). The error bars on the observed atmospheric molar ratios are the 2-sigma calculated for the ratios with linmix_err.pro (http://idlastro.gsfc.nasa.gov/ftp/pro/math/linmix_err.pro).

Figure 10: Bottom-up (inventory-derived) emission estimates and top-down emission scenarios for CH_4, C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12} and C_6H_6 in Weld County. The vertical bars show scenario 1 average values and the error bars indicate the minimum and maximum values for the three scenarios described in Table 4.

Tables

Table 1: Locations of a subset of the NOAA ESRL Towers and Aircraft Profile Sites used in this study. STR and WGC in Northern California are collaborations with Department of Energy Environmental Energy Technologies Division at Lawrence Berkeley National Laboratory (PI: Marc Fischer). The last column gives the altitudes of the quasi-daily flask air samples used in this study. We use midday data for all sites, but at Niwot Ridge Forest we used night time data to capture background air from summertime downslope flow. We also show the location information of SGP, a NOAA ESRL aircraft site in north central Oklahoma, for which we used samples taken below 650 meters altitude.

Site Code	City	State	Latitude ^{o}North	Longitude ^{o}East	Elevation (meters above sea level)	Sampling Height (meters above ground)
BAO	Erie	Colorado	40.05	105.01	1584	300
LEF	Park Falls	Wisconsin	45.93	90.27	472	396
NWF	Niwot Ridge	Colorado	40.03	105.55	3050	23
STR	San Francisco	California	37.7553	122.45	254	232
WGC	Walnut Grove	California	38.265	121.49	0	91
WKT	Moody	Texas	31.32	97.33	251	457
SGP*	Southern Great Plains	Oklahoma	36.80	97.50	314	< 650

* aircraft discrete air samples

Table 2: List of the Front Range Mobile Lab measurement and flasks sampling surveys. Some trips (#1, 2, 3, 4, 6) sampled air using the flask only. Surveys # 5 and 7 used only the continuous analyzers on the Mobile Lab with no discrete flask collection. The last two trips targeted flask sampling close to known point or area sources based on the continuous methane measurement display in the Mobile Lab.

Road Survey #	**Road Survey Date**	**Geographical Area / Target sources**	**Measurements/ Sampling Technique**
1	**June 4**	Boulder	12 flasks
2	**June 11**	Boulder + Foothills	12 flasks
3	**June 19**	NOAA-Longmont-Fort Collins-Greeley (Oil and Gas Drilling, Feedlots)	24 flasks
4	**July 1**	NOAA - Denver	12 flasks
5	**July 9**	Around Denver	Picarro
6	**July 14**	NOAA - Greeley	12 flasks
7	**July 15**	NOAA-Greeley	Picarro
8	**July 25**	BAO surroundings Dacono Natural Gas Compressor - Feedlot	Picarro + 8 flasks
9	**July 31**	"Regional" CH_4 enhancements, Landfill, Corn field	Picarro + 12 flasks

Table 3: Correlation slopes and r^2 for various species measured in the BAO tower midday air flask samples for summer (June to August, when more than 25 samples exist) and winter (November to April) over the time period spanning August 2007 to April 2010. The three wind sectors used in Figure 3 are also used here with a 30-min average wind speed threshold of 2.5 m/s. Also shown are the slopes derived from flask samples collected by the Mobile Lab in summer 2008. The slope is in bold when r^2 is higher than 0.7 and the slope is not shown when r^2 is less than 0.4. The number of data points (n) used for the slope and r^2 calculations are provided. All slope units are ppb/ppb, except for C_6H_6/C_3H_8, C_6H_6/CO and C_2H_2/CO, which are in ppt/ppb. We used the IDL routine linmix_err.pro for the calculations with the following random measurement errors: 2ppb for CH_4 and CO and 5% for C_3H_8, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12}, C_2H_2, and C_6H_6.

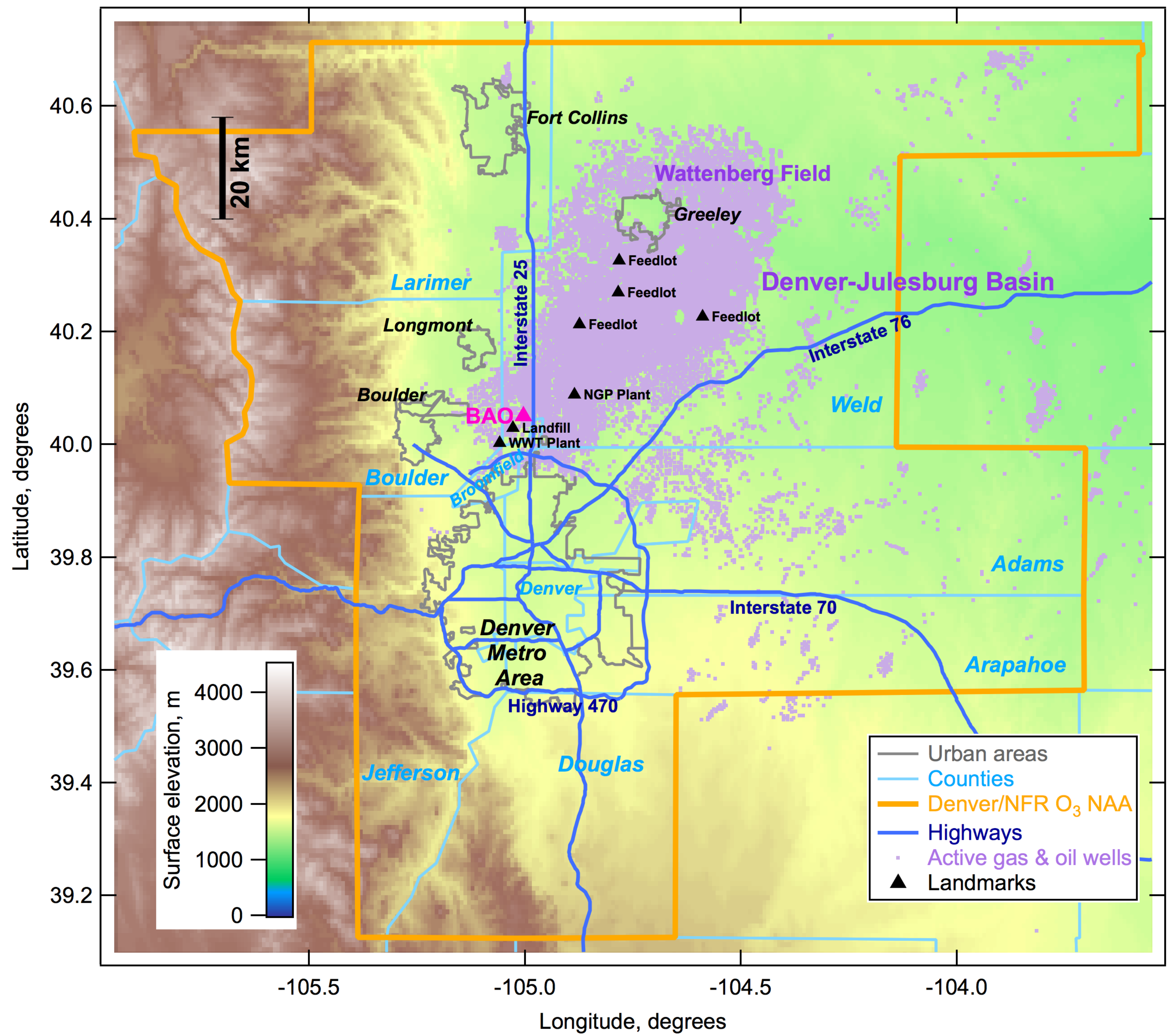
Sector		**BAO North and East**						**BAO South**			**BAO West**			**Mobile Lab**		
Season		**summer**			**winter**			**winter**			**winter**			**summer**		
Molar ratios y/x	**units**	**slope**	r^2	n	**slope**	r^2	n	**slope**	r^2	n	**slope**	r^2	n	**slope**	r^2	n
C_3H_8/ CH_4	ppb/ ppb	**0.104 ±0.005**	0.85	81	**0.105 ±0.004**	0.90	115	0.079 ±0.008	0.53	130	**0.085 ±0.005**	0.73	148	**0.095 ±0.007**	0.76	77
nC_4H_{10}/ C_3H_8	ppb/ ppb	**0.447 ±0.013**	1.00	81	**0.435 ±0.005**	1.0	120	**0.449 ±0.011**	0.98	131	**0.434 ±0.006**	1.00	151	**0.490 ±0.011**	1.00	85
iC_5H_{12}/ C_3H_8	ppb/ ppb	**0.14 1 ±0.004**	1.00	81	**0.134 ±0.004**	0.98	120	**0.142 ±0.009**	0.81	121	**0.130 ±0.004**	0.94	151	**0.185 ±0.011**	0.81	85
nC_5H_{12}/ C_3H_8	ppb/ ppb	**0.150 ±0.003**	1.00	81	**0.136 ±0.004**	0.98	120	**0.142 ±0.006**	0.90	131	**0.133 ±0.003**	0.91	151	**0.186 ±0.008**	0.92	85
C_6H_6/ C_3H_8	ppt/ ppb	10.1 ±1.2	0.67	49	**8.2 ±0.5**	0.79	117	-	0.33	130	-	0.39	150	**17.9 ±1.1**	0.95	46
C_6H_6/ CO	ppt/ ppb	2.89 ±0.40	0.58	53	3.18 ±0.24	0.69	112	**1.57 ±0.08**	0.85	123	**1.81 ±0.08**	0.83	148	**1.82 ±0.12**	0.89	39
C_2H_2/ CO	ppt/ ppb	**3.15 ±0.33**	0.85	81	**7.51 ±0.39**	0.85	100	**5.03 ±0.17**	0.92	110	**5.85 ±0.25**	0.86	131	**4.32 ±0.28**	0.89	39
C_6H_6/ C_2H_2	ppt/ ppt	0.51 ±0.09	0.55	50	**0.34 ±0.02**	0.90	103	**0.27 ±0.02**	0.90	111	**0.32 ±0.02**	0.96	132	**0.37 ±0.04**	0.75	39

Table 4: Bottom-up (inventory-derived) emission estimates and top-down emissions scenarios for CH_4 and C_3H_8 in Weld County.

	Bottom-Up Estimates				**Top-Down Scenarios[e]: Venting**			**Top-Down Scenarios[e]: TOTAL Bottom-Up Flashing + Top-Down Venting**			**Top-Down Scenarios[e]: % of production vented[f]**		
Gg/yr	**Flashing[b]**	**Venting[c]**	**Flashing + venting**	**% of production vented[d]**	**1**	**2**	**3**	**1**	**2**	**3**	**1**	**2**	**3**
methane	**11.2**	53.1	64.3	**1.68%**	118.4	92.5	157	**129.6**	103.7	168.2	**4.0%**	3.1%	5.3%
min[a]	**4**	42	46		86.5	67.6	114.7	90.5	**71.6**	118.7	2.9%	**2.3%**	3.8%
max[a]	**23**	63	86		172.6	134.9	228.9	195.6	157.9	**251.9**	5.8%	4.5%	**7.7%**
propane	**18.3**	7.8	26.1		17.4	10.2	28	**35.7**	28.5	46.3			
min[a]	**14**	1	15		12.7	7.5	20.5	26.7	**21.5**	34.5			
max[a]	**24**	28	52		25.3	14.9	40.8	49.3	38.9	**64.8**			

[a] The minimum and maximum values reported here come from the ensemble of 16 condensate tank emissions speciation profiles provided by CDPHE.
[b] The bottom-up flashing emissions for methane and propane were calculated using the 2008 estimate of total VOC flash emissions derived by averaging the WRAP estimate for 2006 and the projection for 2010 (Cf. section 4.3).
[c] The bottom-up venting emissions for methane and propane were calculated using the WRAP Phase III inventory estimate for the total volume of natural gas vented and the GWA 77 natural gas composition profiles.
[d] Using the WRAP Phase III inventory data set and assumptions, including a CH_4 mean molar ratio of 77.44% for the vented natural gas and a molar volume for the gas of 22.4 L/mol.
[e] The CH_4-to-C_3H_8 molar ratio for vented natural gas is 18.75 (WRAP report estimate) for scenario 1, 15.43 for scenario 2 (median of molar ratios in GWA data set) and 24.83 for scenario 3 (mean of molar ratios in GWA data set).
[f] Using the assumptions of a CH_4 molar ratio of 77% for the vented natural gas and a molar volume for the gas of 23.6 L/mol (Pressure= 14.73 pounds per square inch and Temperature= 60^{o}F) as used by the EIA [EIA, 2004].

1316



Fort Collins
Wattenberg Field
Greeley
Feedlot
Feedlot
Feedlot
Feedlot
Denver-Julesburg Basin
Interstate 76
Larimer
Longmont
Interstate 25
NGP Plant
Boulder
BAO
Landfill
WWT Plant
Weld
Boulder
Broomfield
Adams
Denver
Interstate 70
Denver
Metro
Area
Arapahoe
Highway 470
Jefferson
Douglas
20 km
Surface elevation, m
4000
3000
2000
1000
0
Urban areas
Counties
Denver/NFR O_3 NAA
Highways
Active gas & oil wells
Landmarks
40.6
40.4
40.2
40.0
39.8
39.6
39.4
39.2
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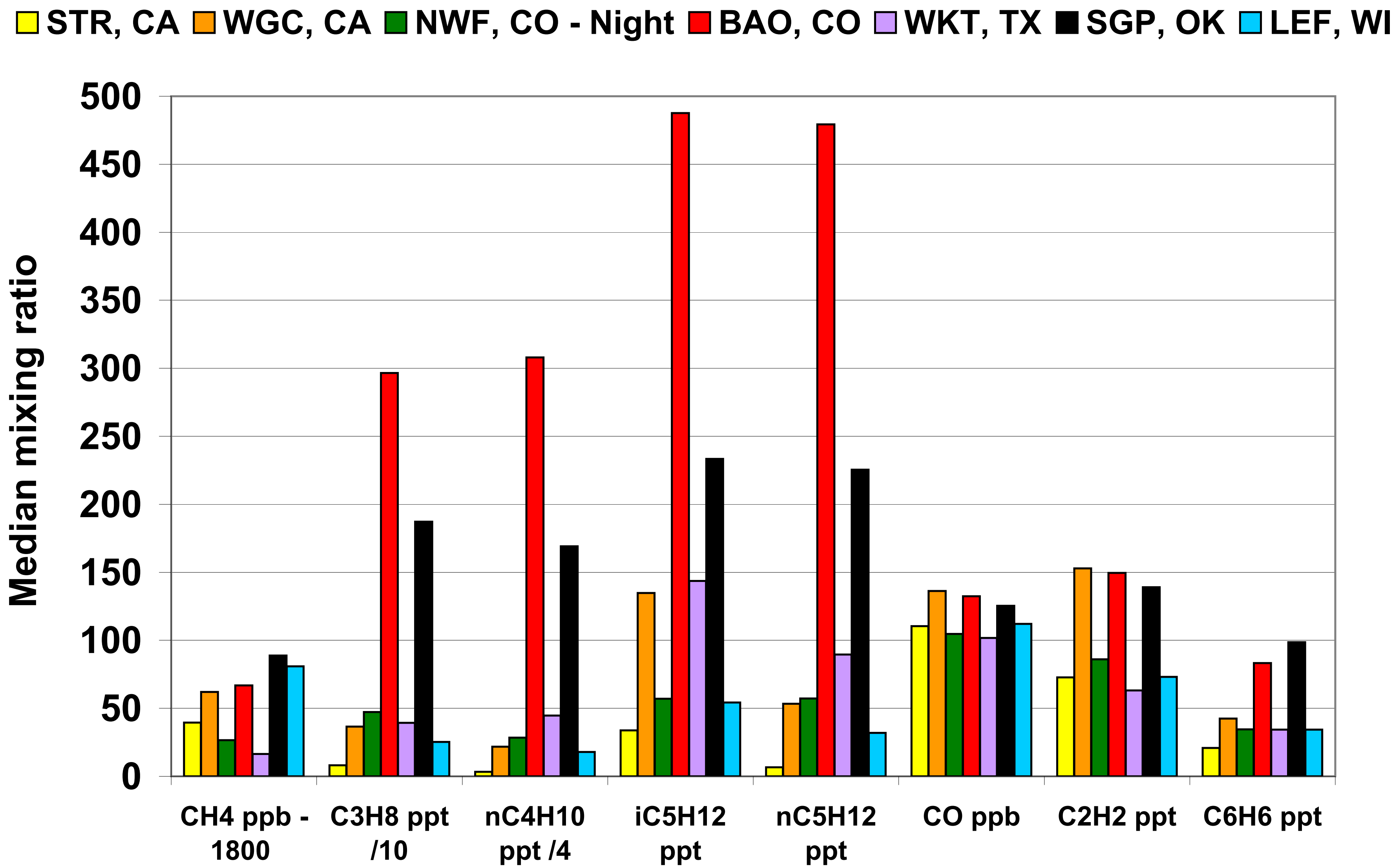
-105.0
-104.5
-104.0
Longitude, degrees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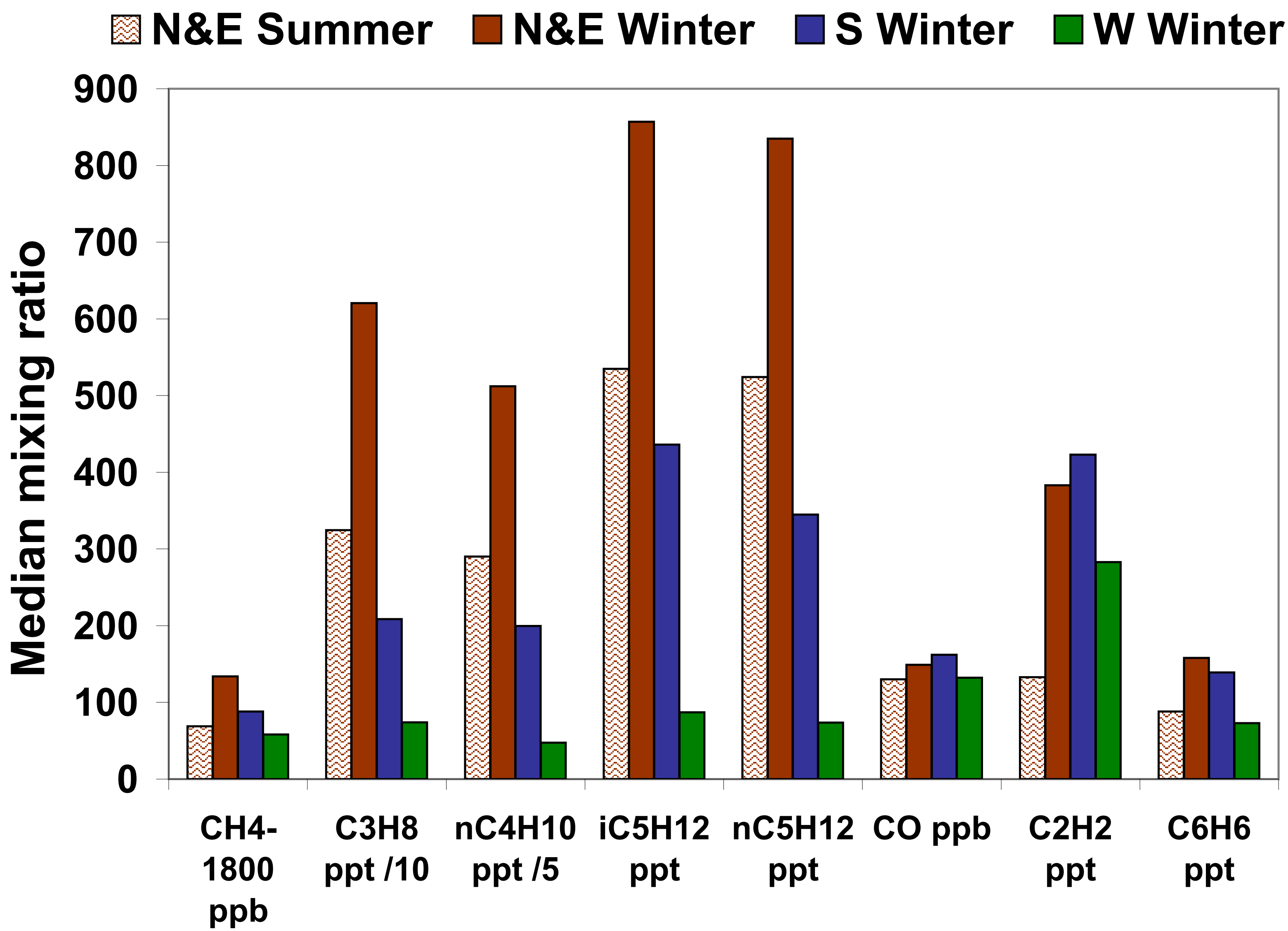
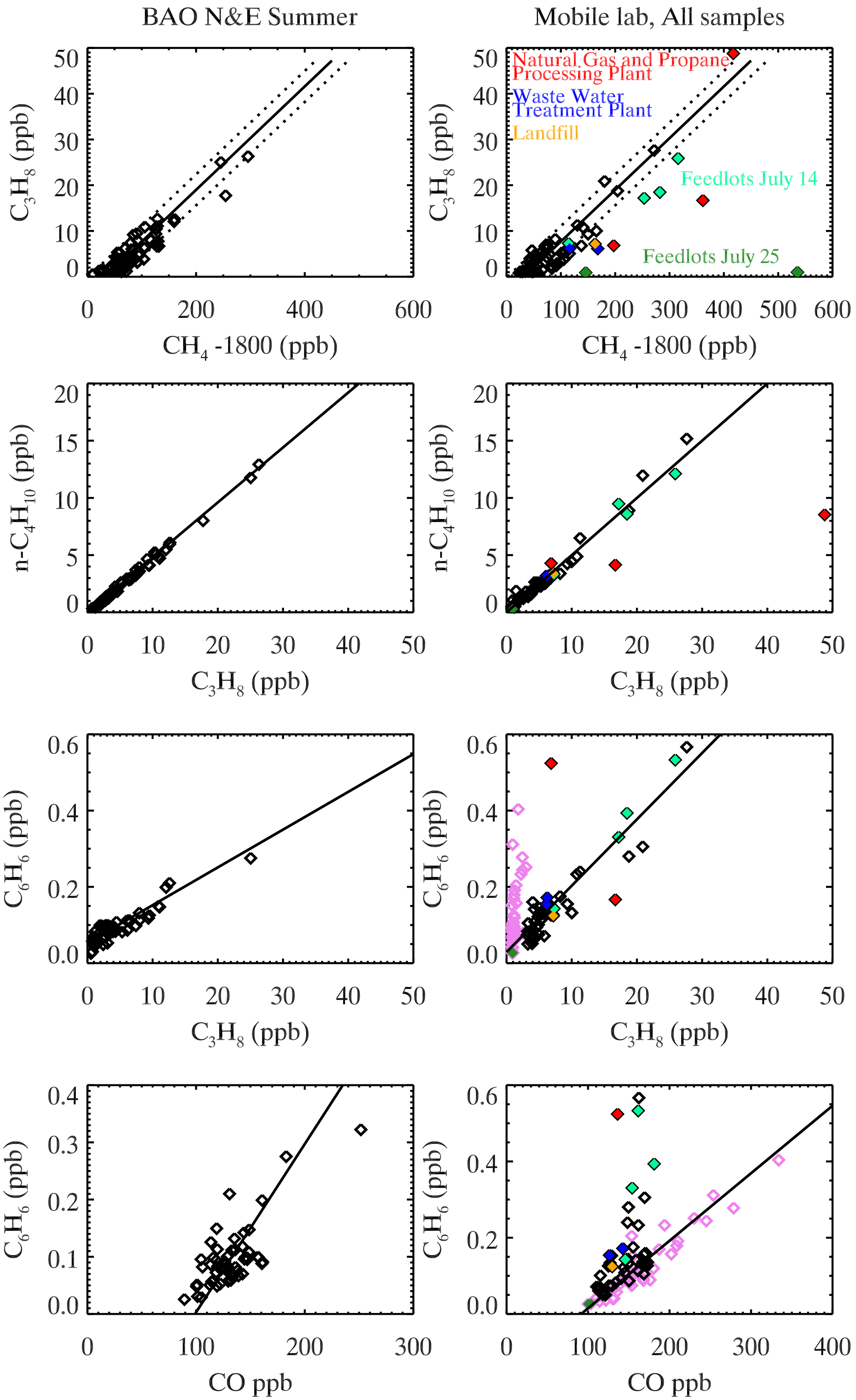
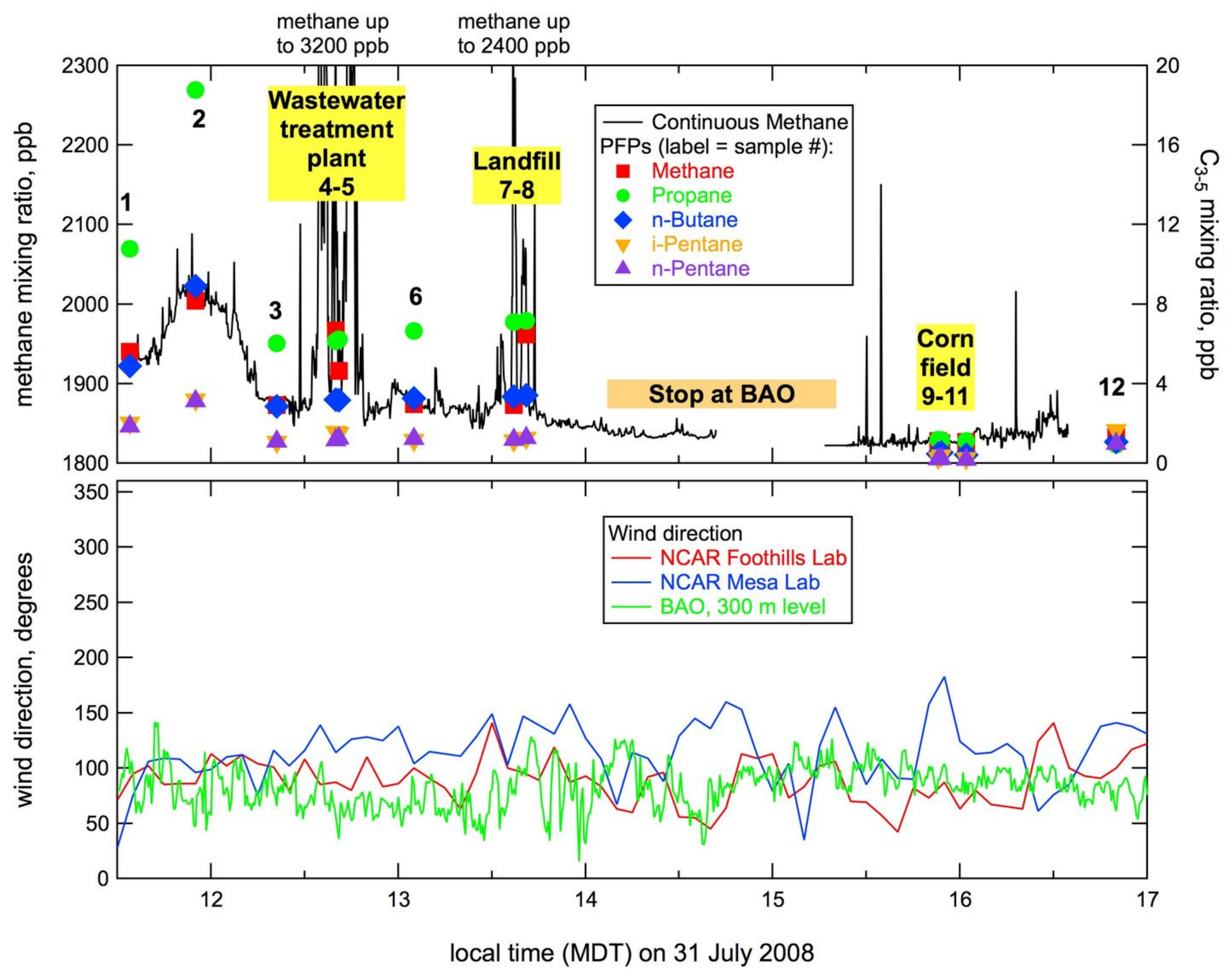
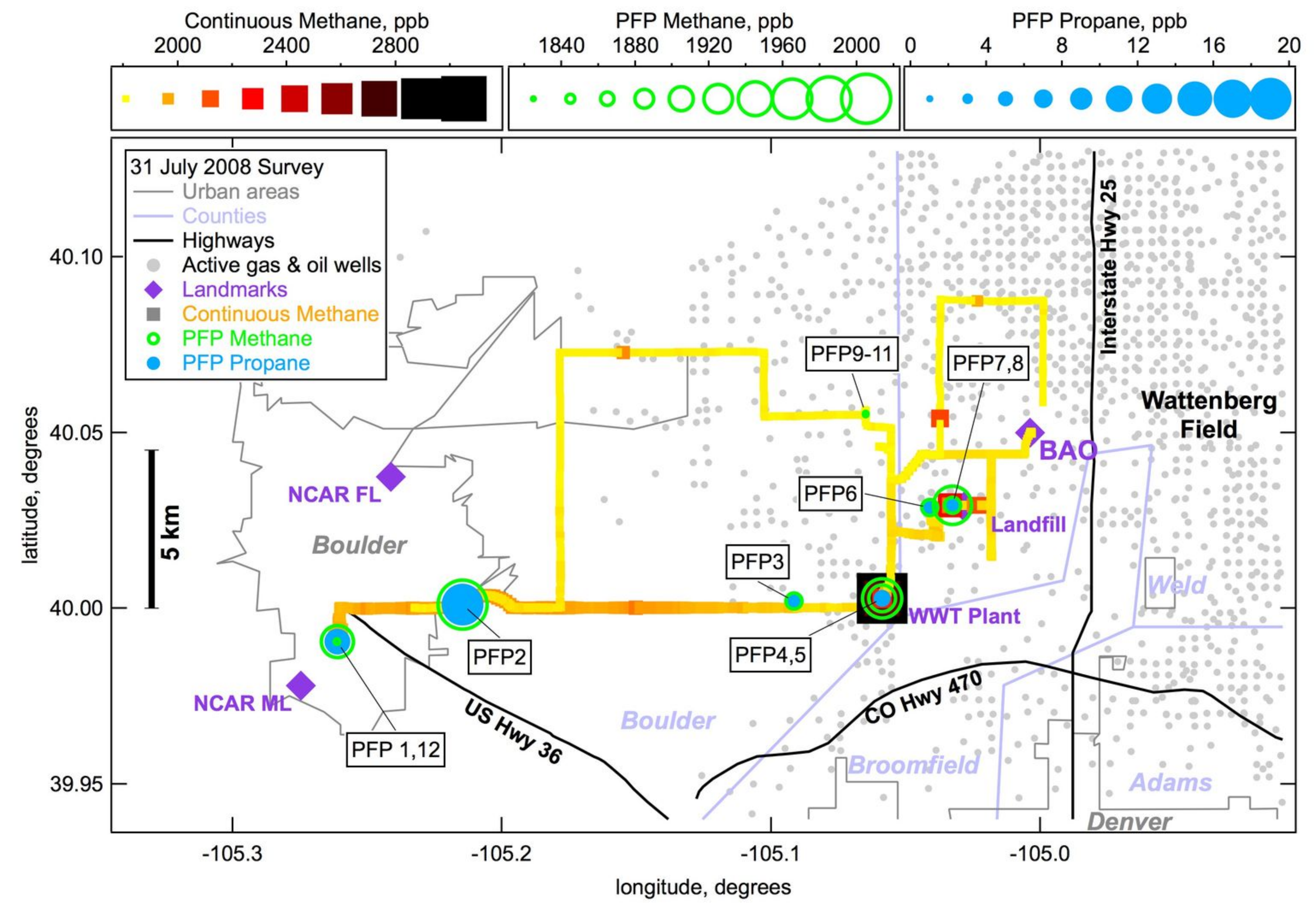
WGC, CA
NWF, CO - Night
BAO, CO
WKT, TX
SGP, OK
LEF, WI
Median mixing ratio
500
450
400
350
300
250
200
150
100
50
0
CH4 ppb - 1800
C3H8 ppt /10
nC4H10 ppt /4
iC5H12 ppt
nC5H12 ppt
CO ppb
C2H2 ppt
C6H6 ppt


N&E Summer
N&E Winter
S Winter
W Winter
Median mixing ratio
900
800
700
600
500
400
300
200
100
0
CH4-1800 ppb
C3H8 ppt /10
nC4H10 ppt /5
iC5H12 ppt
nC5H12 ppt
CO ppb
C2H2 ppt
C6H6 ppt



BAO N&E Summer
Mobile lab, All samples
Natural Gas and Propane Processing Plant
Waste Water Treatment Plant
Landfill
Feedlots July 14
Feedlots July 25
C_3H_8 (ppb)
CH_4 -1800 (ppb)
n-C_4H_{10} (ppb)
C_6H_6 (ppb)
CO ppb


methane up
to 3200 ppb
methane up
to 2400 ppb
Wastewater treatment plant 4-5
Landfill 7-8
Stop at BAO
Corn field 9-11
1
2
3
6
12
Continuous Methane
PFPs (label = sample #):
Methane
Propane
n-Butane
i-Pentane
n-Pentane
methane mixing ratio, ppb
C_{3-5} mixing ratio, ppb
Wind direction
NCAR Foothills Lab
NCAR Mesa Lab
BAO, 300 m level
wind direction, degrees
local time (MDT) on 31 July 2008



Continuous Methane, ppb
2000
2400
2800
PFP Methane, ppb
1840
1880
1920
1960
2000
PFP Propane, ppb
0
4
8
12
16
20
31 July 2008 Survey
Urban areas
Counties
Highways
Active gas & oil wells
Landmarks
Continuous Methane
PFP Methane
PFP Propane
Interstate Hwy 25
Wattenberg Field
PFP9-11
PFP7,8
BAO
NCAR FL
PFP6
Landfill
Boulder
5 km
PFP3
WWT Plant
PFP2
PFP4,5
Weld
NCAR ML
PFP 1,12
US Hwy 36
Boulder
CO Hwy 470
Broomfield
Adams
Denver
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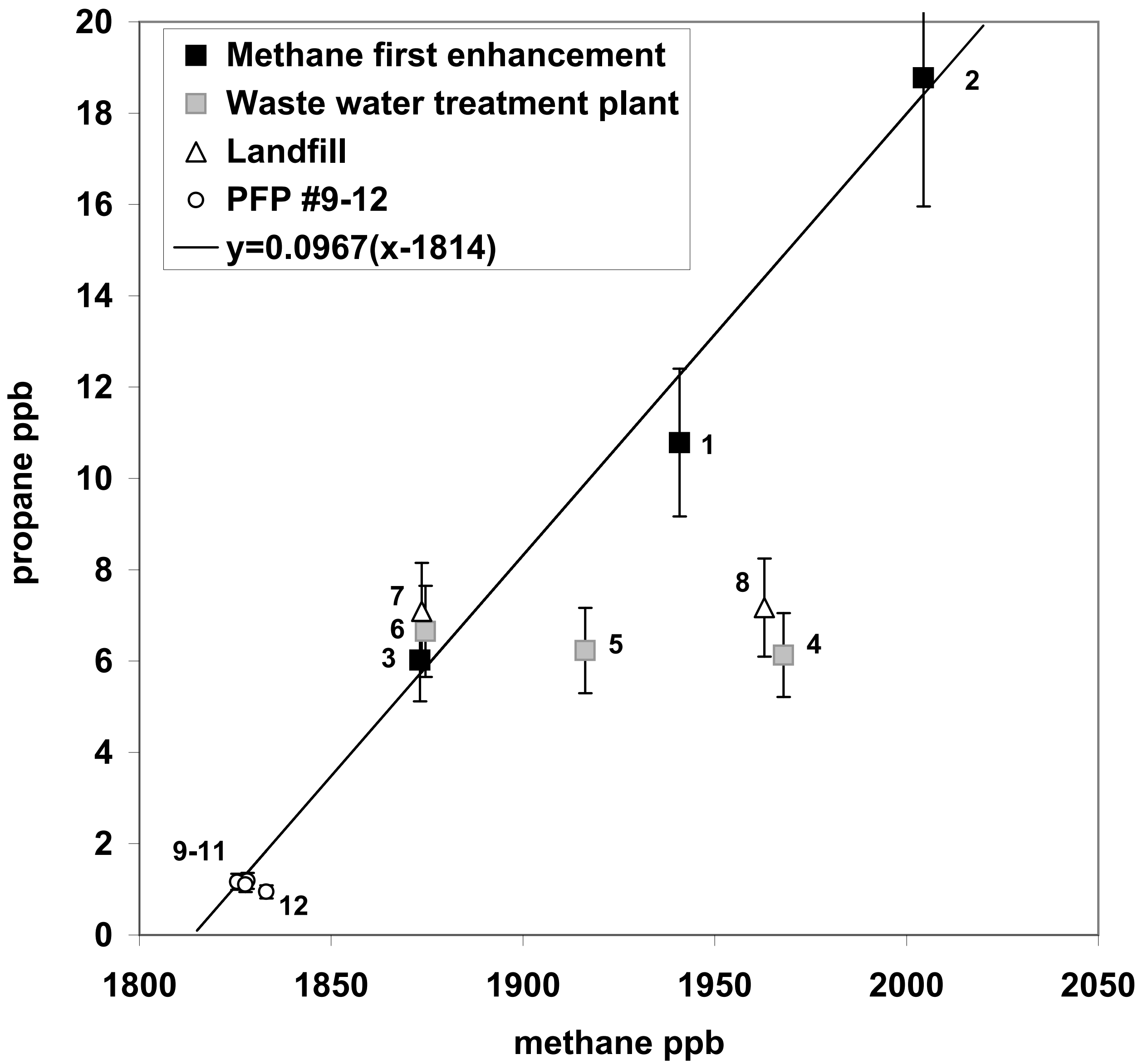
longitude, degrees



Methane first enhancement
Waste water treatment plant
Landfill
PFP #9-12
y=0.0967(x-1814)
propane ppb
methane ppb
0
2
4
6
8
10
12
14
16
18
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1800
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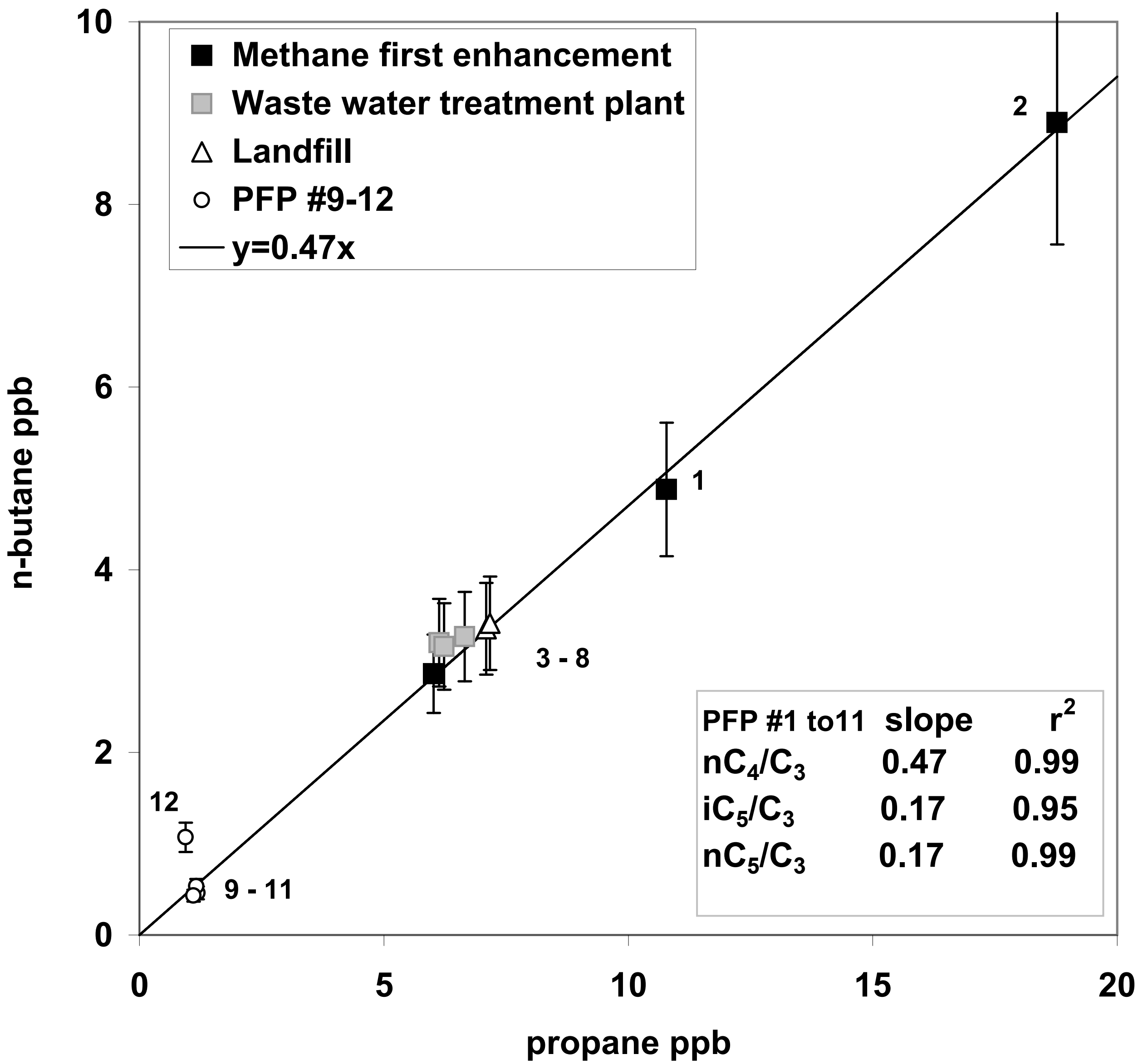
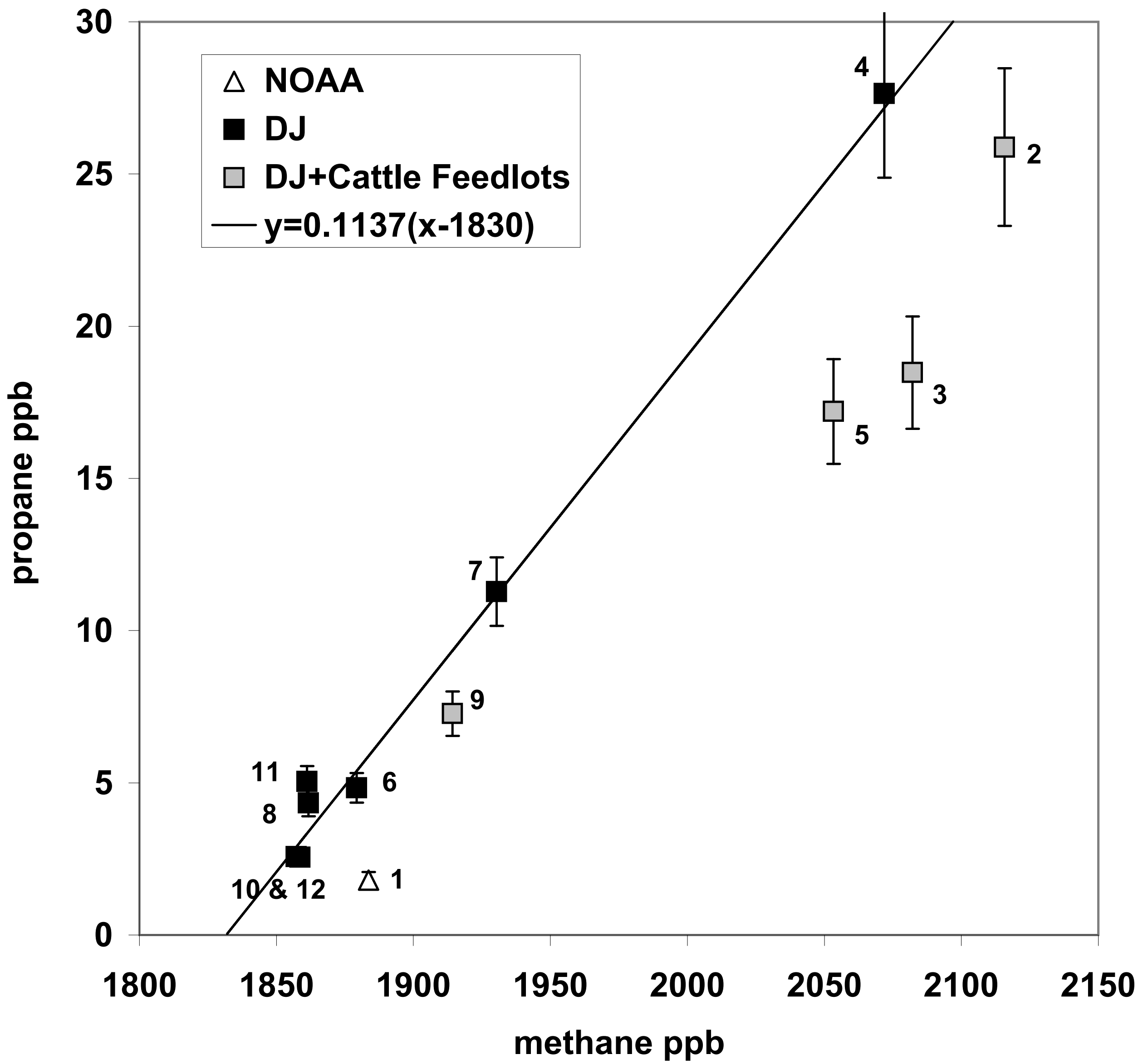
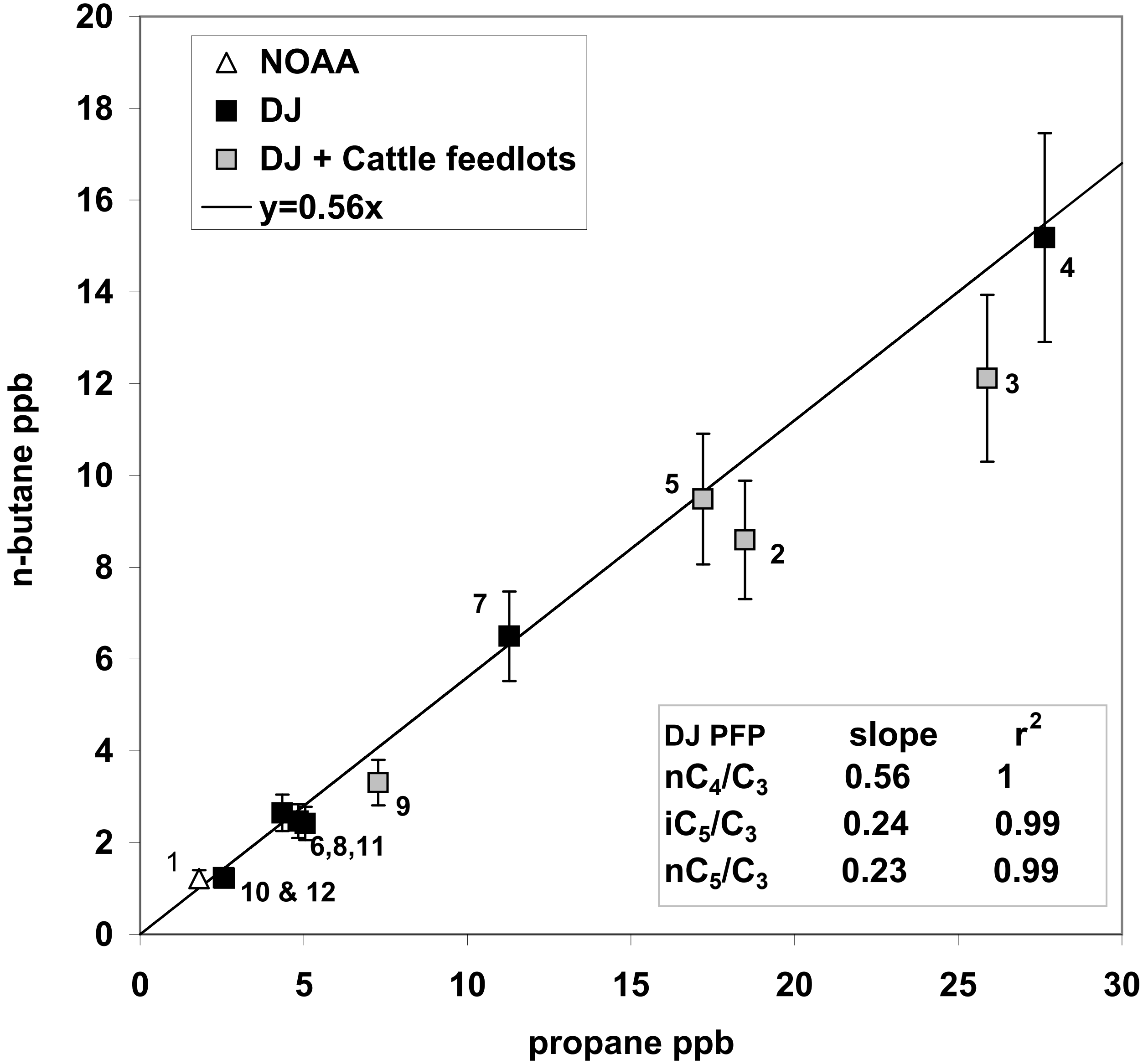
6
7
8
9-11
12

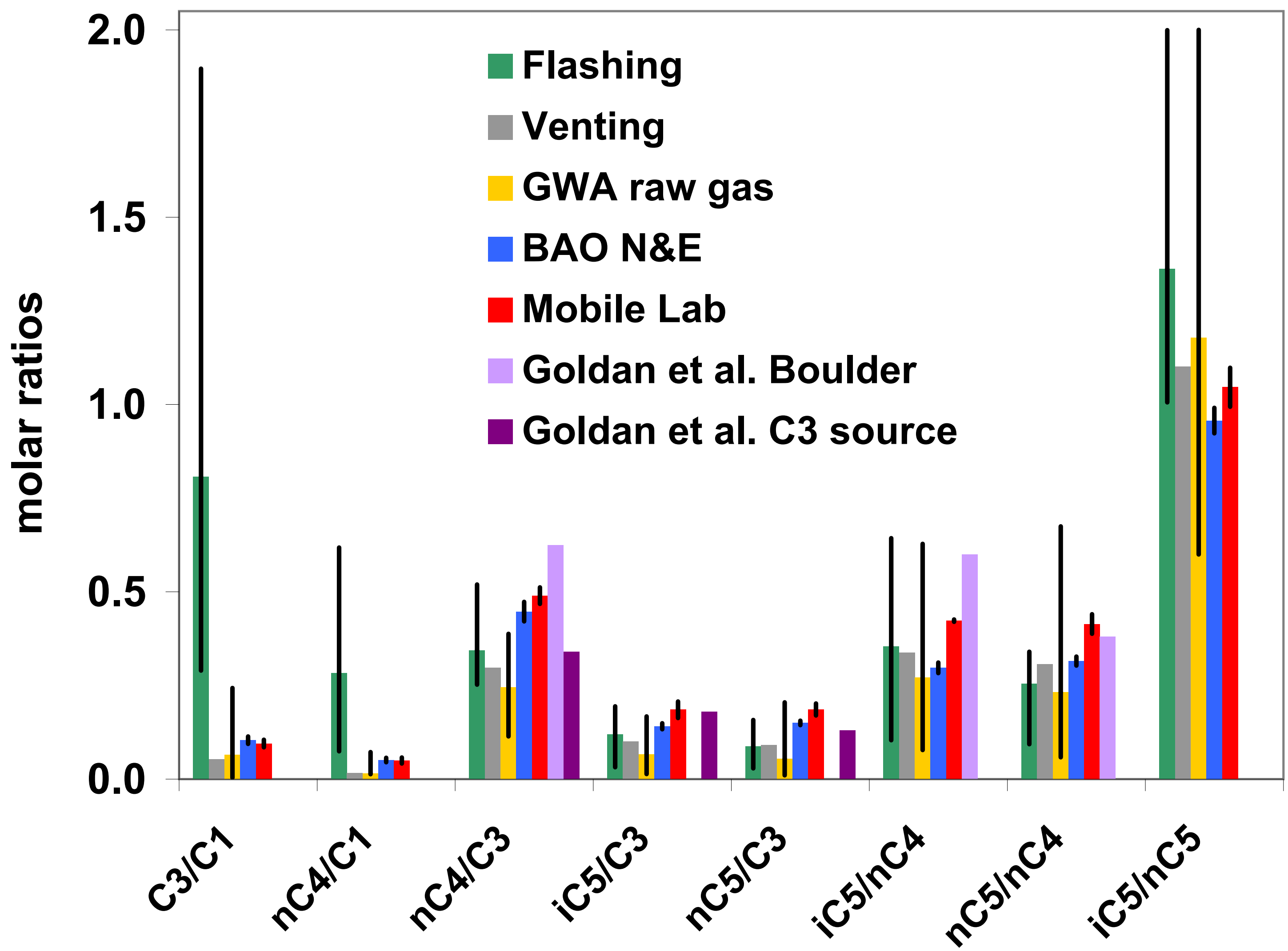

Methane first enhancement
Waste water treatment plant
Landfill
PFP #9-12
y=0.47x
2
1
3 - 8
12
9 - 11
PFP #1 to11 slope r^2
nC$_4$/C$_3$ 0.47 0.99
iC$_5$/C$_3$ 0.17 0.95
nC$_5$/C$_3$ 0.17 0.99
n-butane ppb
propane ppb
0
2
4
6
8
10
0
5
10
15
20



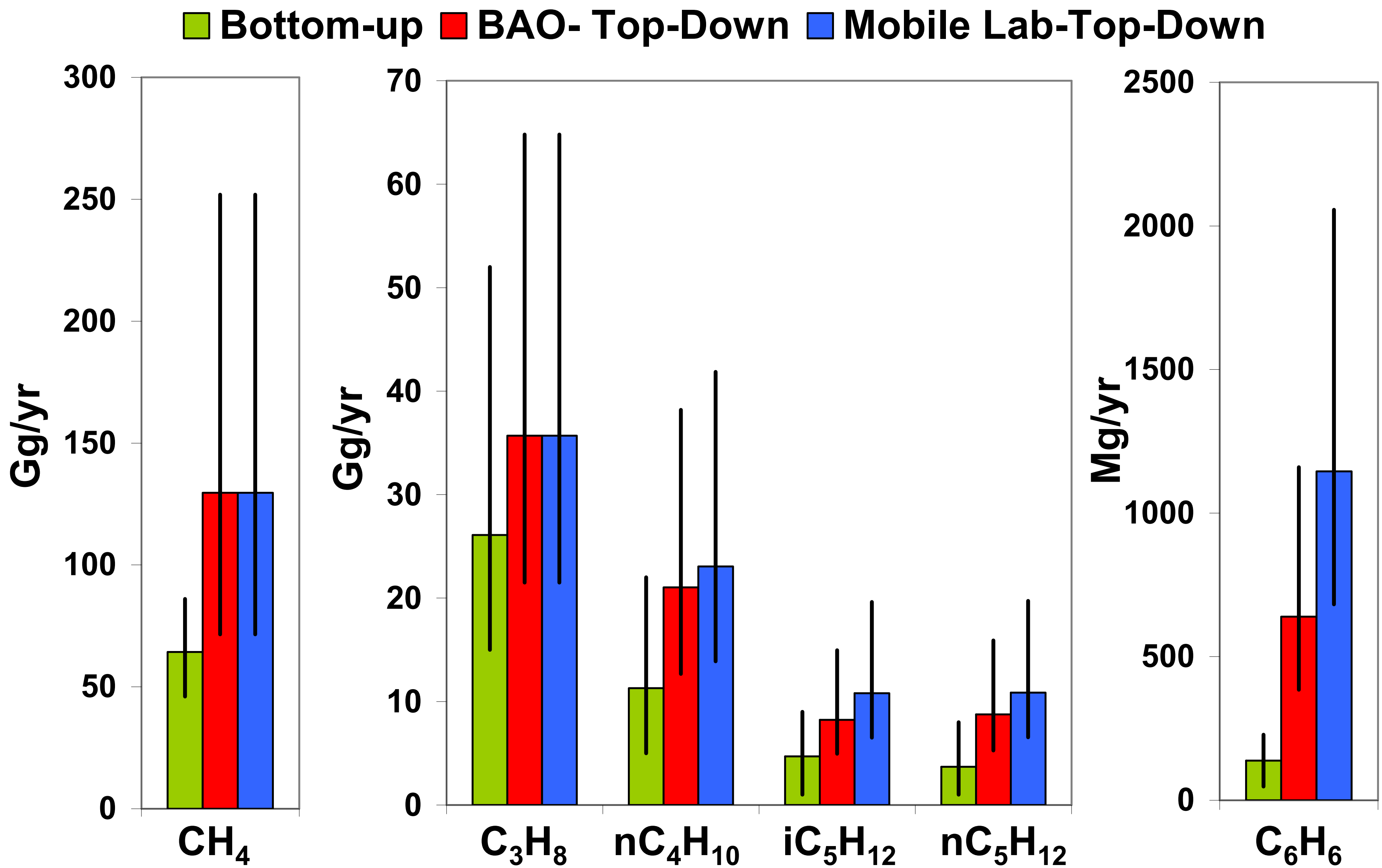
NOAA
DJ
DJ+Cattle Feedlots
y=0.1137(x-1830)
propane ppb
methane ppb
0
5
10
15
20
25
30
1800
1850
1900
1950
2000
2050
2100
2150
1
2
3
4
5
6
7
8
9
10 & 12
11



NOAA
DJ
DJ + Cattle feedlots
y=0.56x
n-butane ppb
propane ppb
0
2
4
6
8
10
12
14
16
18
20
0
5
10
15
20
25
30
1
2
3
4
5
6,8,11
7
9
10 & 12
DJ PFP slope r^2
nC_4/C_3 0.56 1
iC_5/C_3 0.24 0.99
nC_5/C_3 0.23 0.99



Flashing
Venting
GWA raw gas
BAO N&E
Mobile Lab
Goldan et al. Boulder
Goldan et al. C3 source
molar ratios
2.0
1.5
1.0
0.5
0.0
C3/C1
nC4/C1
nC4/C3
iC5/C3
nC5/C3
iC5/nC4
nC5/nC4
iC5/nC5



Bottom-up
BAO- Top-Down
Mobile Lab-Top-Down
Gg/yr
0
50
100
150
200
250
300
CH4
Gg/yr
0
10
20
30
40
50
60
70
C3H8
nC4H10
iC5H12
nC5H12
Mg/yr
0
500
1000
1500
2000
2500
C6H6

Supplementary Tables

Table 1S: Methane source estimates in Colorado (Gg CH4 /yr, for 2005)

Table 2S: Natural gas and crude oil production in Weld County, Colorado, and the US for 2005 and 2008 (Bcf=Billion cubic feet)

Table 3S: Total VOC and benzene source estimates for Weld County in different bottom-up inventories. Source categories may not sum to total due to rounding.
Sources: WRAP for year 2006 [Bar Ilan et al., 2008a], CDPHE for 2008 [CDPHE, personal communication], NEI 2005 [EPA, 2008], NEI 2008 [EPA, 2011b]

Table 4S: Inventory and measurement derived molar ratios for the various data sets plotted on Figure 9. Flashing emissions composition is based on EPA TANK model runs for 16 condensate tanks located in the DJB and sampled in 2002 [CDPHE, personal communication 2010]. Venting emissions composition is based on an average raw gas weight composition profile provided by Bar-Ilan et al. [2008a] and derived private data from several natural gas producing companies in the DJB. To get a range of distribution for vented emissions, we use the molar composition provided by COGCC for raw gas samples collected at 77 wells in the DJB in December 2006. The BAO NE summer data and Mobile Lab data are the same as in Table 3. The Goldan et al. data for samples collected west of Boulder in February 1991 are based on Goldan et al. [1995] Table 1 and Figure 5.

Supplementary Figures

Figure 1S: Time series of the Boulder Atmospheric Observatory flask data (collected between 17 and 21 UTC).

Figure 2S: Denver - Northern Front Range NAA VOC emissions inventories for oil and gas exploration, production and processing operations, developed by Bar-Ilan et al. [2008a,b]. The 2006 inventory is based on reported emissions for large condensate tanks and other permitted source categories identified with a (*) in the legend. Other source estimates are based on activity data and emissions factors. The 2010 ?projection? inventory was extrapolated based on oil and gas production trends, the 2006 emissions data, and federal and state regulations for emissions control of permitted sources that were ?on the book as of early 2008?. We distinguish three types of emissions based on distinct VOC speciation profiles used in the WRAP inventory: (1) flashing emissions from small and large condensate tanks; (2) venting emissions associated with leaks of raw natural gas at the well site or in the gathering network of pipelines; and (3) other emissions such as compressor engines (3% of total source), truck loading of condensate (1%), heaters, drill rigs, workover rigs, exempt engines, and spills which have different VOC emissions profiles.

Figure 3S: PFP samples collected during the mobile survey on July 14, 2008. The size of the symbols indicates the mixing ratio of PFP methane (red circles) and propane (green circles). The labels indicate the PFP sample number. NGP Plant = natural gas processing plant, WWT = Lafayette wastewater treatment plant.

Figure 4S: Molar composition of the venting (grey) and flashing (green) emissions data used to construct the bottom-up VOC emissions inventory for the DJB (average venting profile shared by Bar-Ilan et al. [2008a], flashing emissions profile based on EPA TANK runs for 16 condensate tanks in the DJB [CDPHE, personal communication]). For flashing emissions we show the average (green bar) and the minimum and maximum (error bars) molar fractions for all species. Also shown are the average (yellow bars) and the minimum and maximum molar fractions (error bars) of the various alkanes derived from the COGCC raw gas composition data for 77 wells in the Greater Wattenberg Area (GWA) (no aromatics data for this data set).

Figure 5S: Flow diagram of the calculation of speciated bottom-up emission estimates.

Figure 6S: Bottom-up flashing and venting emission estimates for Weld County in 2008. The colored bars indicate the mean emission estimates while the error bars indicate the minimum and maximum estimates. The WRAP inventory for the DJB used only one vented gas profile and therefore the corresponding Venting-WRAP emission estimates do not have error bars.

Table 1S: Methane source estimates in Colorado (Gg CH_4 /yr, for 2005)
Source: Strait et al., 2007

Natural gas systems	238
Coal mining	233
Enteric fermentation	143
Landfills	71
Manure management	48
Waste water treatment plants	24
Petroleum systems	10
Colorado total	767

Table 2S: Natural gas and crude oil production in Weld County, Colorado, and the US for 2005 and 2008 (Bcf=Billion cubic feet)

Source: COGCC (Weld County) and EIA (Colorado and US)

Year	**2005**			**2008**		
Gross withdrawal/ production	Natural gas *Bcf/yr*	Crude oil *Million barrels/yr*	Lease condensate *Million barrels/yr*	Natural gas *Bcf/yr*	Crude oil *Million barrels/yr*	Lease condensate *Million barrels/yr*
Weld County (% of Colorado)	188.5 (16.5%)	11.7 (51.3%)	na	202.1 (15.3%)	17.3 (71.8%)	na
DNFR NAA	201.1	12.6	na	214.1	18.5	na
Colorado	1144	22.8	5	1403	24.1	7
USA	23457	1890.1	174	25636	1811.8	173

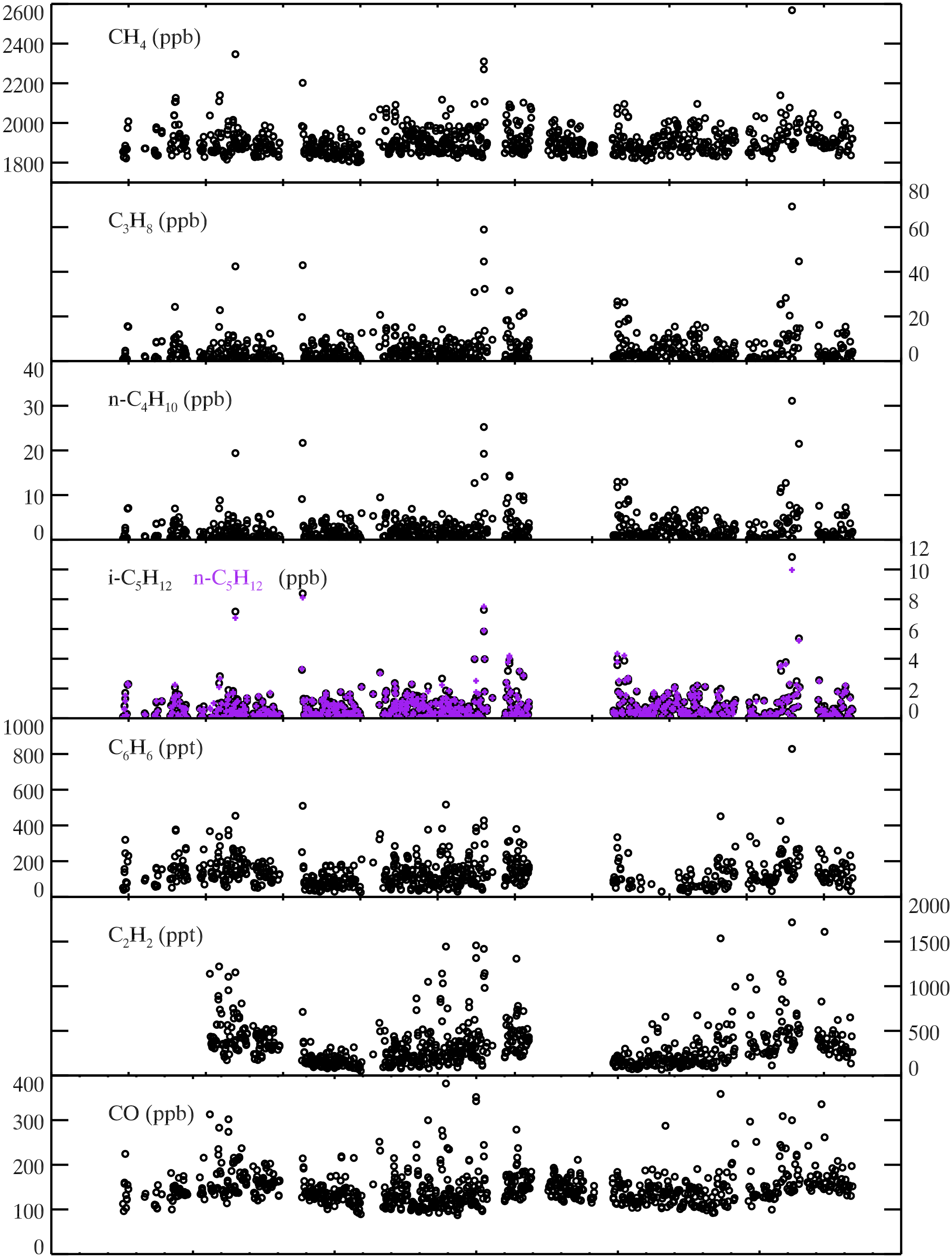
Table 3S: Total VOC and benzene source estimates for Weld County in different bottom-up inventories. Source categories may not sum to total *due to rounding.*
Sources: WRAP for year 2006 [Bar Ilan et al., 2008a], CDPHE for 2008 [CDPHE, personal communication], NEI 2005 [EPA, 2008], NEI 2008 [EPA, 2011b]

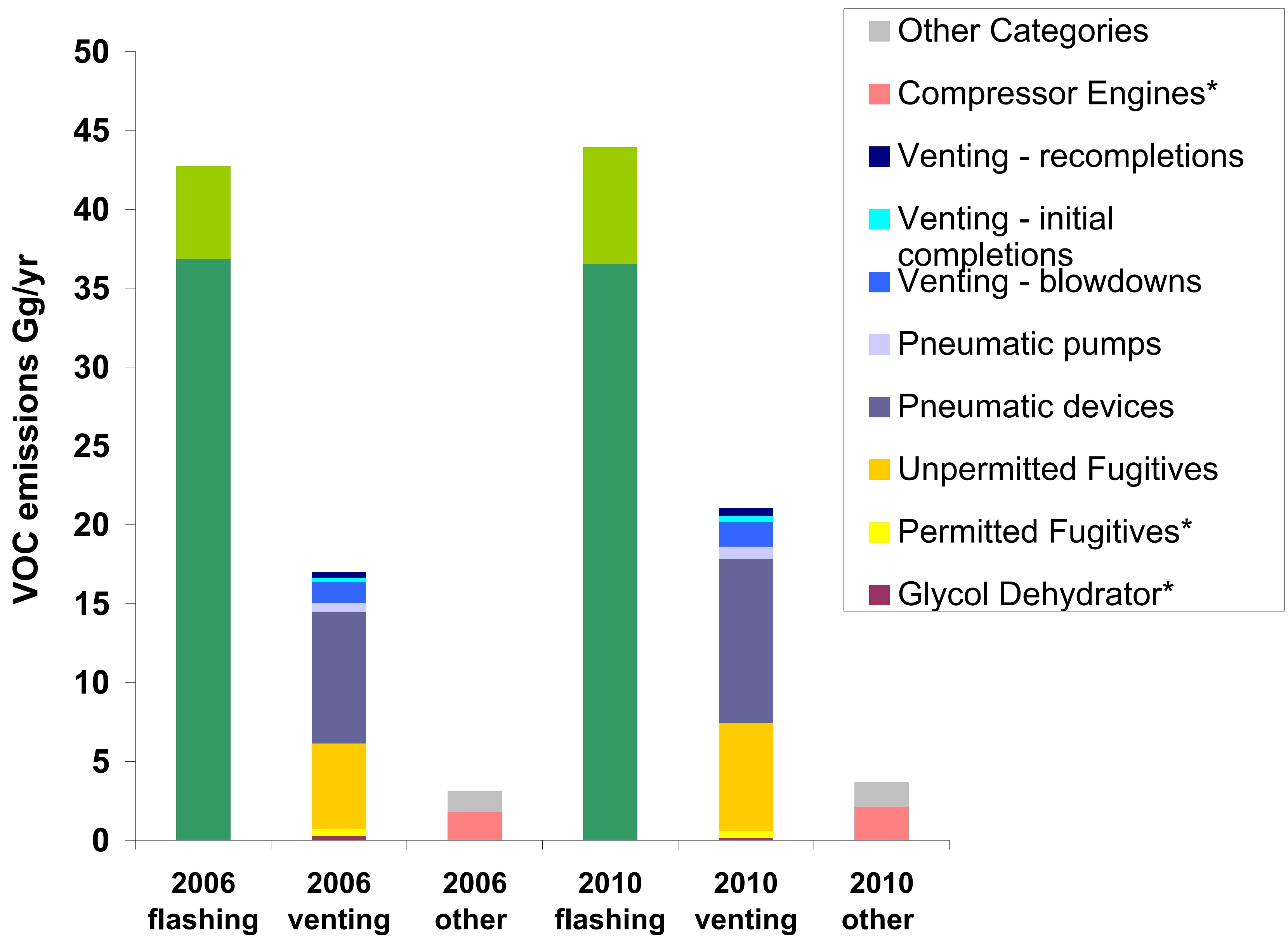
Species		**Total VOC**				**Benzene**		
Year		**2006**	**2008**	**2008**	**2005**	**2008**	**2008**	**2005**
Source		**WRAP**	**CDPHE**	**NEI**	**NEI**	**CDPHE**	**NEI**	**NEI**
unit		**Gg/yr**				**Mg/yr**		
On-Road			2533	2968	3532	95.4	121.4	160.1
Non-road + rail + aircraft			1596	1313	1626	44.2	36.0	45.9
Wood burning			232	-	187	8.8	-	5.7
Solvent utilization			201	1914	2819	-	-	31.6
Surface coating			1235	-	421	-	-	0.8
Oil and gas area		21145*	-	-	-	-	-	-
Oil and gas point	Large Condensate tanks	34790	17811	18163	-	21.3	21.5	1120.0
	Glycol dehydrators	218	220	-	-	15.1	-	47.6
	Gas sweetening	11	11	-	-	6.6	-	7.8
	Internal Combustion Engines	1996	1692	-	-	16.0	-	-
	Other	304	844	646	-	2.8	23.1	1.6
	Total	*37015*	*20628*	*18810*	*-*	*61.8*	*44.6*	*1177.0*
Gas stations/Gasoline bulk terminals			697	965	1270	8.0	11.1	11.8
Forest and prescribed fires			110		207	8.3	-	2.4
Fossil Fuel combustion Point (non O&G)			196	1880	651	0.5	16.5	3.9
Other point			547	680	335	1.0	15.6	12.3
Other area			1078		605	2.3		4.6
Total for available source categories		58160	29051	28530	11654	230.5	245.2	1454

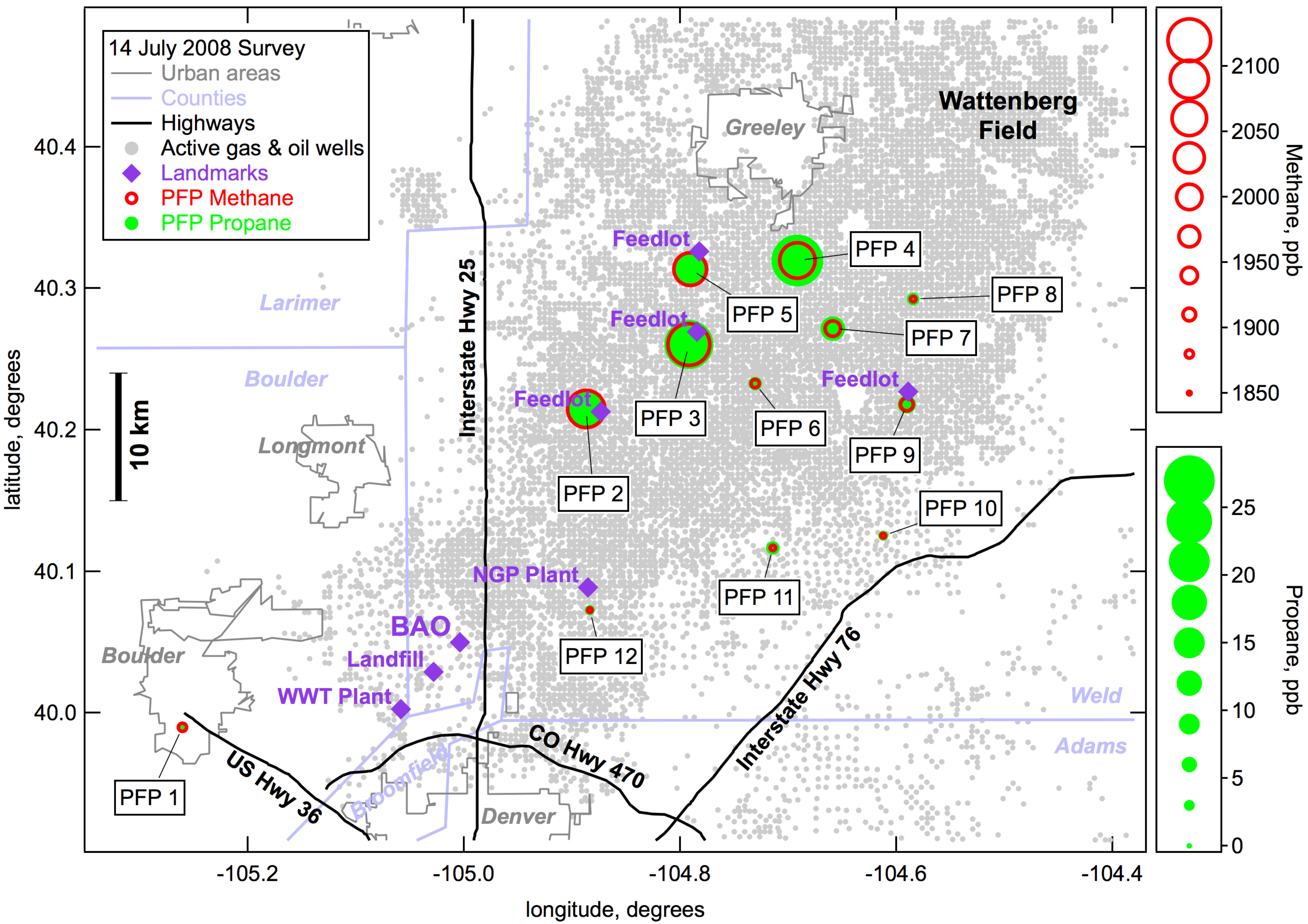
*Source categories included are: Pneumatic devices and pumps, small condensate tanks, fugitive emissions, heaters, process heaters, venting, truck loading, spills, NG production: flares, flanges and connections, and others.

Table 4S: Inventory and measurement derived molar ratios for the various data sets plotted on Figure 9. Flashing emissions composition is based on EPA TANK model runs for 16 condensate tanks located in the DJB and sampled in 2002 [CDPHE, personal communication 2010]. Venting emissions composition is based on an average raw gas weight composition profile provided by Bar-Ilan et al. [2008a] and derived private data from several natural gas producing companies in the DJB. To get a range of distribution for vented emissions, we use the molar composition provided by COGCC for raw gas samples collected at 77 wells in the DJB in December 2006. The BAO NE summer data and Mobile Lab data are the same as in Table 3. The Goldan et al. data for samples collected west of Boulder in February 1991 are based on Goldan et al. [1995] Table 1 and Figure 5.

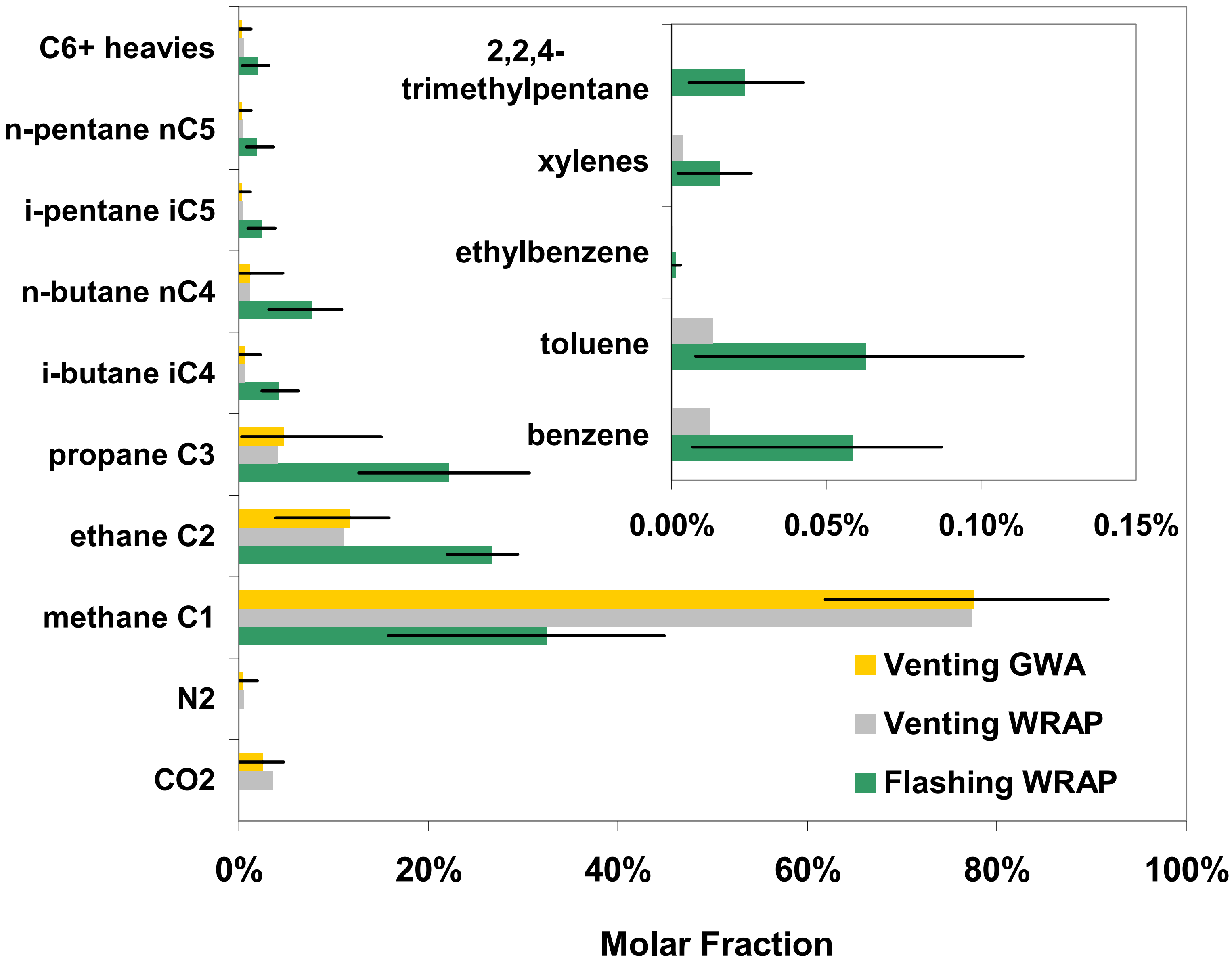
Data Set		**C_3/C_1**	**nC_4/C_1**	**nC_4/C_3**	**iC_5/C_3**	**nC_5/C_3**	**iC_5/nC_4**	**nC_5/nC_4**	**iC_5/nC_5**
WRAP Flashing emissions	Median	0.807	0.283	0.343	0.119	0.088	0.354	0.255	1.362
	Mean	0.654	0.271	0.339	0.123	0.088	0.354	0.262	1.271
	Min	0.290	0.074	0.252	0.032	0.029	0.104	0.093	1.006
	Max	1.896	0.618	0.519	0.194	0.158	0.643	0.340	1.999
WRAP Venting emissions		0.053	0.016	0.298	0.100	0.091	0.338	0.307	1.101
GWA raw gas	Median	0.065	0.015	0.245	0.066	0.054	0.270	0.231	1.179
	Mean	0.064	0.017	0.253	0.071	0.061	0.280	0.239	1.226
	Min	0.004	0.015	0.114	0.014	0.010	0.078	0.058	0.600
	Max	0.243	0.072	0.388	0.167	0.205	0.628	0.674	2.000
Bottom-up VOC inventory: WRAP Flashing + GWA Venting (mean profiles)		0.154	0.049	0.316	0.099	0.078	0.313	0.245	1.274
BAO NE -summer		0.104	0.051	0.447	0.141	0.150	0.297	0.315	0.957
Mobile Lab		0.095	0.050	0.510	0.185	0.186	0.423	0.414	1.046
Goldan et al.- all data		-	-	0.340	0.180	0.130	-	-	-
Goldan et al. C_3 source		-	-	0.625	-	-	0.600	0.380	-

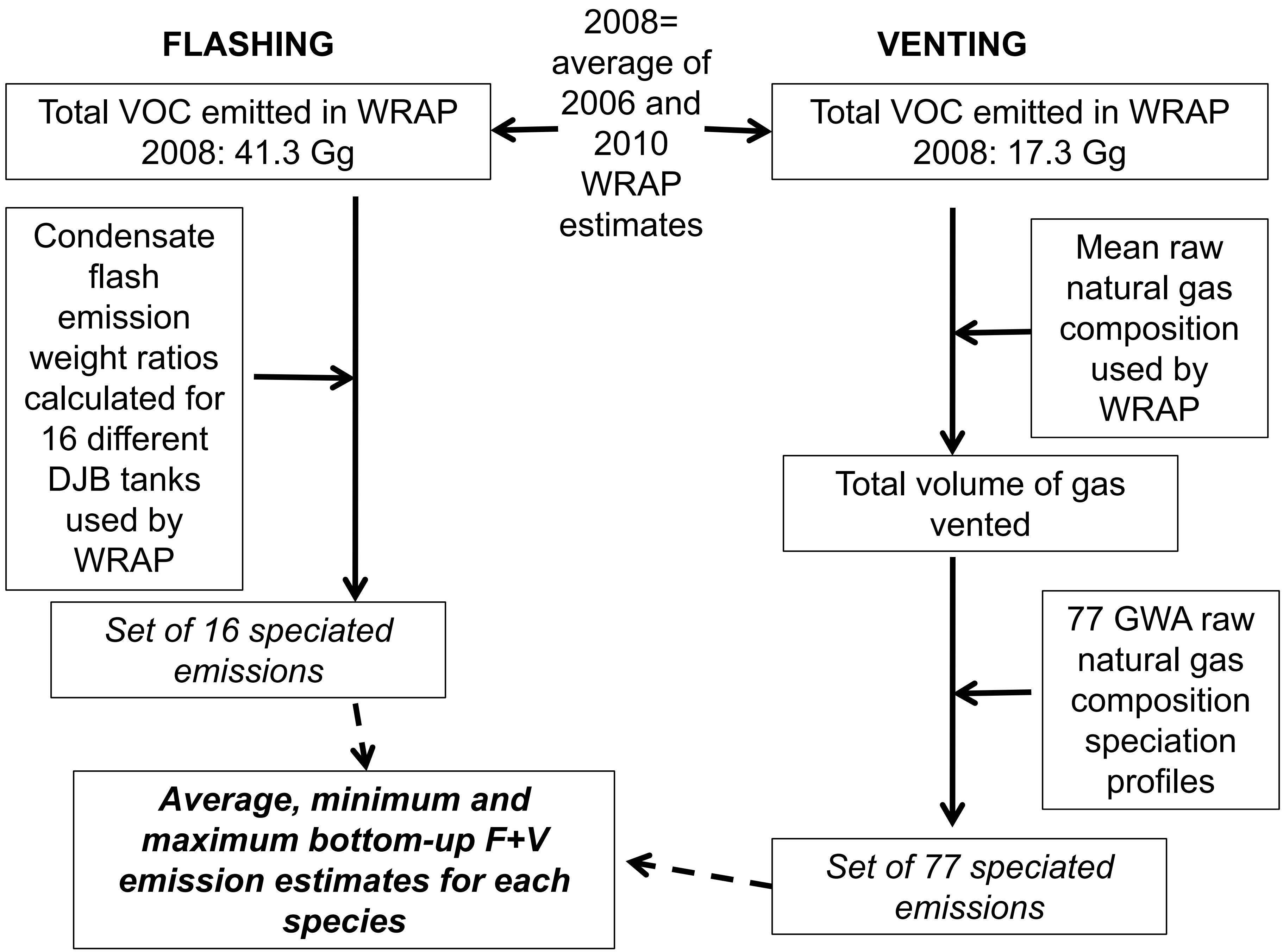

CH4 (ppb)
2600
2400
2200
2000
1800
C3H8 (ppb)
80
60
40
20
0
n-C4H10 (ppb)
40
30
20
10
0
i-C5H12 n-C5H12 (ppb)
12
10
8
6
4
2
0
C6H6 (ppt)
1000
800
600
400
200
0
C2H2 (ppt)
2000
1500
1000
500
0
CO (ppb)
400
300
200
100
0

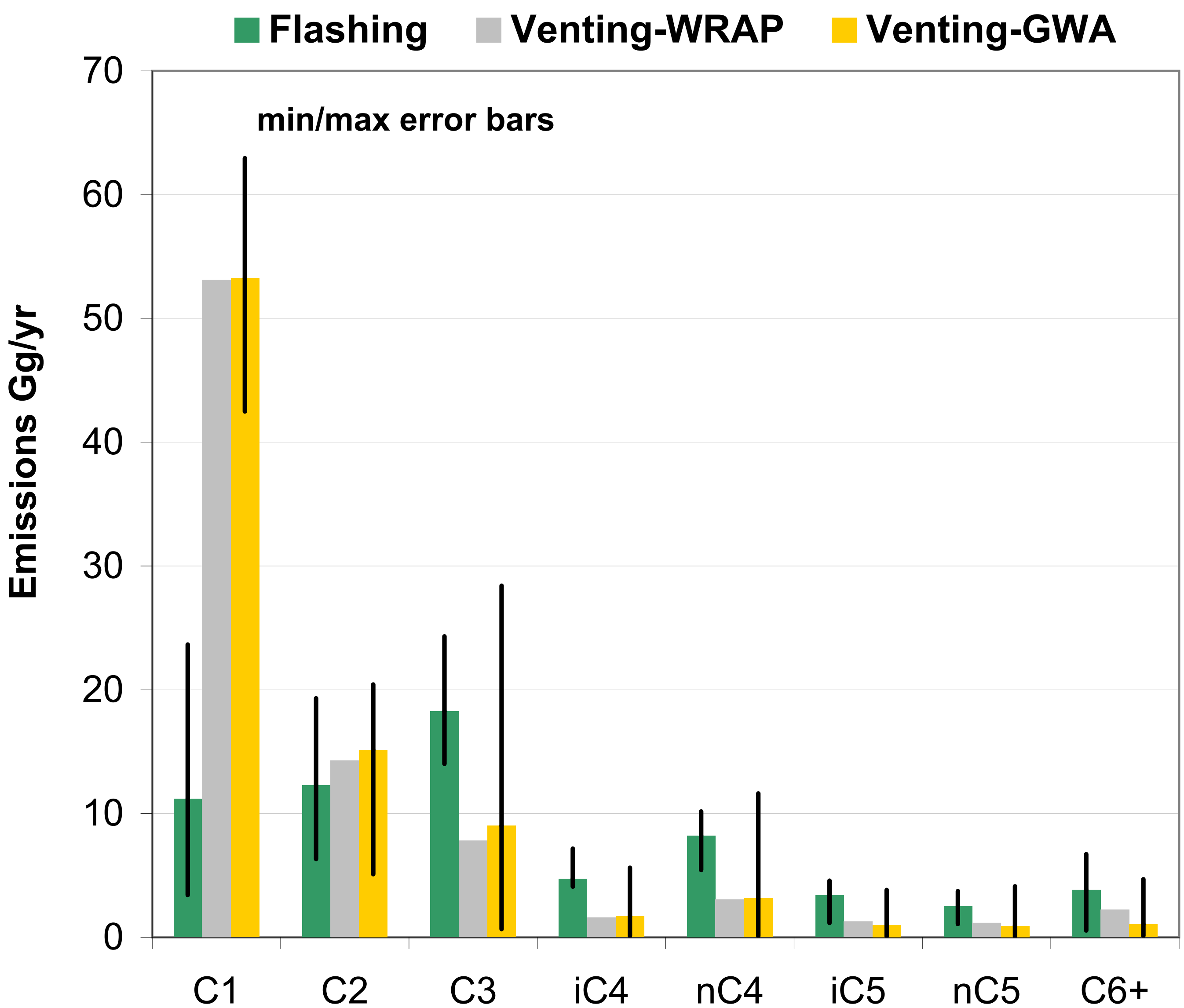

VOC emissions Gg/yr
50
45
40
35
30
25
20
15
10
5
0
2006 flashing
2006 venting
2006 other
2010 flashing
2010 venting
2010 other
Other Categories
Compressor Engines*
Venting - recompletions
Venting - initial completions
Venting - blowdowns
Pneumatic pumps
Pneumatic devices
Unpermitted Fugitives
Permitted Fugitives*
Glycol Dehydrator*



14 July 2008 Survey
Urban areas
Counties
Highways
Active gas & oil wells
Landmarks
PFP Methane
PFP Propane
Wattenberg Field
Greeley
Longmont
Boulder
Denver
Broomfield
Larimer
Boulder
Weld
Adams
10 km
Interstate Hwy 25
Interstate Hwy 76
CO Hwy 470
US Hwy 36
Feedlot
Feedlot
Feedlot
Feedlot
NGP Plant
BAO
Landfill
WWT Plant
PFP 1
PFP 2
PFP 3
PFP 4
PFP 5
PFP 6
PFP 7
PFP 8
PFP 9
PFP 10
PFP 11
PFP 12
40.4
40.3
40.2
40.1
40.0
latitude, degrees
-105.2
-105.0
-104.8
-104.6
-104.4
longitude, degrees
2100
2050
2000
1950
1900
1850
Methane, ppb
25
20
15
10
5
0
Propane, ppb


C6+ heavies
n-pentane nC5
i-pentane iC5
n-butane nC4
i-butane iC4
propane C3
ethane C2
methane C1
N2
CO2
0%
20%
40%
60%
80%
100%
Molar Fraction
2,2,4-trimethylpentane
xylenes
ethylbenzene
toluene
benzene
0.00%
0.05%
0.10%
0.15%
Venting GWA
Venting WRAP
Flashing WRAP


FLASHING
VENTING
2008= average of 2006 and 2010 WRAP estimates
Total VOC emitted in WRAP 2008: 41.3 Gg
Total VOC emitted in WRAP 2008: 17.3 Gg
Condensate flash emission weight ratios calculated for 16 different DJB tanks used by WRAP
Mean raw natural gas composition used by WRAP
Total volume of gas vented
77 GWA raw natural gas composition speciation profiles
Set of 16 speciated emissions
Set of 77 speciated emissions
Average, minimum and maximum bottom-up F+V emission estimates for each species


Flashing
Venting-WRAP
Venting-GWA
min/max error bars
Emissions Gg/yr
70
60
50
40
30
20
10
0
C1
C2
C3
iC4
nC4
iC5
nC5
C6+

Methane leaks erode green credentials of natural gas

Losses of up to 9% show need for broader data on US gas industry's environmental impact.

Jeff Tollefson

02 January 2013

Natural-gas wells such as this one in Colorado are increasingly important to the US energy supply.

DAVID ZALUBOWSKI/AP PHOTO

Scientists are once again reporting alarmingly high methane emissions from an oil and gas field, underscoring questions about the environmental benefits of the boom in natural-gas production that is transforming the US energy system.

The researchers, who hold joint appointments with the National Oceanic and Atmospheric Administration (NOAA) and the University of Colorado in Boulder, first sparked concern in February 2012 with a study[1] suggesting that up to 4% of the methane produced at a field near Denver was escaping into the atmosphere. If methane — a potent greenhouse gas — is leaking from fields across the country at similar rates, it could be offsetting much of the climate benefit of the ongoing shift from coal- to gas-fired plants for electricity generation.

Industry officials and some scientists contested the claim, but at an American Geophysical Union (AGU) meeting in San Francisco, California, last month, the research team reported new Colorado data that support the earlier work, as well as preliminary results from a field study in the Uinta Basin of Utah suggesting even higher rates of methane leakage — an eye-popping 9% of the total production. That figure is nearly double the cumulative loss rates estimated from industry data — which are already higher in Utah than in Colorado.

"We were expecting to see high methane levels, but I don't think anybody really comprehended the true magnitude of what we would see," says Colm Sweeney, who led the aerial component of the study as head of the aircraft programme at NOAA's Earth System Research Laboratory in Boulder.

Whether the high leakage rates claimed in Colorado and Utah are typical across the US natural-gas industry remains unclear. The NOAA data represent a "small snapshot" of a much larger picture that the broader scientific community is now assembling, says Steven Hamburg, chief scientist at the Environmental Defense Fund (EDF) in Boston, Massachusetts.

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- The global energy challenge: Awash with carbon
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The NOAA researchers collected their data in February as part of a broader analysis of air pollution in the Uinta Basin, using ground-based equipment and an aircraft to make detailed measurements of various pollutants, including methane concentrations. The researchers used atmospheric modelling to calculate the level of methane emissions required to reach those concentrations, and then compared that with industry data on gas production to obtain the percentage escaping into the atmosphere through venting and leaks.

The results build on those of the earlier Colorado study[1] in the Denver–Julesburg Basin, led by NOAA scientist Gabrielle Pétron (see *Nature* **482,** 139–140; 2012). That study relied on pollution measurements taken in 2008 on the ground and from a nearby tower, and estimated a leakage rate that was about twice as high as official figures suggested. But the team's methodology for calculating leakage — based on chemical analysis of the pollutants — remains in dispute. Michael Levi, an energy analyst at the Council on Foreign Relations in New York, published a peer-reviewed comment[2] questioning the findings and presenting an alternative interpretation of the data that would align overall leakage rates with previous estimates.

Pétron and her colleagues have a defence of the Colorado study in press[3], and at the AGU meeting she discussed a new study of the Denver–Julesburg Basin conducted with scientists at Picarro, a gas-analyser manufacturer based in Santa Clara, California. That study relies on carbon isotopes to differentiate between industrial emissions and methane from cows and feedlots, and the preliminary results line up with their earlier findings.

A great deal rides on getting the number right. A study[4] published in April by scientists at the EDF and Princeton University in New Jersey suggests that shifting to natural gas from coal-fired generators has immediate climatic benefits as long as the cumulative leakage rate from natural-gas production is below 3.2%; the benefits accumulate over time and are even larger if the gas plants replace older coal plants. By comparison, the authors note that the latest estimates from the US Environmental Protection Agency (EPA) suggest that 2.4% of total natural-gas production was lost to leakage in 2009.

To see if that number holds up, the NOAA scientists are also taking part in a comprehensive assessment of US natural-gas emissions, conducted by the University of Texas at Austin and the EDF, with various industry partners. The initiative will analyse emissions from the production, gathering, processing, long-distance transmission and local distribution of natural gas, and will gather data on the use of natural gas in the transportation sector. In addition to scouring through industry data, the scientists are collecting field measurements at facilities across the country. The researchers expect to submit the first of these studies for publication by February, and say that the others will be complete within a year.

In April, the EPA issued standards intended to reduce air pollution from hydraulic-fracturing operations — now standard within the oil and gas industry — and advocates say that more can be done, at the state and national levels, to reduce methane emissions. “There are clearly opportunities to reduce leakage,” says Hamburg.

Nature **493,** 12 (03 January 2013) doi:10.1038/493012a

References

1. Pétron, G. *et al*. *J. Geophys. Res.* **117**, D04304 (2012).
   Show context — Article ChemPort

2. Levi, M. A. J. *Geophys. Res.* **117**, D21203 (2012).
   Show context — Article

3. Pétron, G. *et al*. *J. Geophys. Res.* (in the press).
   Show context

4. Alvarez, R. A., Pacala, S. W. Winebrake, J. J., Chameides, W. L. & Hamburg, S. P. *Proc. Natl Acad. Sci. USA* **109**, 6435–6440 (2012).
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Comments

2013-01-02 07:43 AM

John Nethery said: One obvious question is: Did any of these studies carry out baseline measurements of methane in these areas prior to any drilling to check the amount of natural leakage via faults and fractures? If such studies were not done then basically the later measurements are irrelevant and conclusions are guesswork.

2013-01-03 06:18 AM

Ko van Huissteden said: The lack of baseline measurements on the environmental impact of unconventional gas is indeed a major problem in quantifying this impact. In general, the gas industry or US government should have taken the responsibility to do these baseline measurements, on groundwater quality, on air pollution and on greenhouse gas emissions. What is happening now with unconventional gas, is comparable to introducing medicines on the market without proper research on its side effects.
However, lack of baseline measurements does not justify dismissing any study on environmental or climate impact, because that would make practically all evaluation of environmental impact impossible and hinder any progress in environmental responsibility. Lack of baseline measurements often can be compensated for by good research design. In this case, any natural leakage of methane can also be accounted for in other ways.

2013-01-04 06:19 AM

Rinaldo Sorgenti said: Very interesting news.

The above subject is largely conditioned by the fact that, undoubtedly, coal at time of burning is releasing about double the CO2 emissions in comparison to gas burning. What I call the "post-combustion" issue.

But, what about the "pre-combustion" issue, in a "Life Cycle Assessment", as it should logically be seen this matter, if really we have to bother about CO2 emissions to the troposphere?

Strangely enough, none or only very few informed people are considering this issue and even the famous UN-IPCC is not considering, accounting and charging to anybody the usual and huge CO2 emissions coming from the hydrocarbons wells extraction, where CO2 (together with H2S and N20) - naturally present underground, commingled with Methane and other gases – are coming out from ground during the fuels extraction.

These "nasty" ancillary gases (CO2, H2S, N20, etc.) are just regularly locally "captured" during wells extraction and then simply "vented" to the atmosphere!

In addition to the above mentioned "nasty" gases, there is also the "Methane fugitive emissions" issue to take into account and in relation to same I think useful to attract your and Mr. Dieter Helm's attention to the attached Study, published last year by the Cornell University – Ithaca/NY (USA): "Methane and GHG footprint of natural Gas from shale formation".

Considering the importance that many people (including the Ue) are placing to the above policy: "i.e.: switching from coal to natural gas for power production", I think that this matter need to be better understood and examined, to avoid that a wrong policy/action negatively influence so much the energy sector, worldwide at a very huge cost for the consumers.

The EPA should help to make this topic clear.

2013-01-04 04:14 AM

Larry Gilman said: Without seeing the work — here summarized secondhand — how do we actually know that lack of baseline is a problem? Pre-post comparison would be ideal, but could not a reasonable approximation of baseline be obtained by making measurements over geologically similar but undrilled areas?

2013-01-06 02:50 AM

Henk Daalder Wind farm wiki said: Natural gas does NOT have green credentials, it is just a fossil fuel, that contributes to the global warming problem.

The US has just been overtaken by China in building wind farms, they should work harder to reclaim this leadership, because wind power is better for the economy that natural gas.
And wind power is really green.
Since 2009 more wind power is build than any other war of generating electricity.

2013-01-09 11:29 AM

Robert Edwards said: Rinaldo Sorgenti is incorrect to assert that no-one considers "precombustion" emissions from fossil fuel extraction. Any life-cycle analysis worthy of the name of course take them into account. They are usually called "upstream emissions" or "production emissions".

2013-01-15 01:30 AM

Ronald Klusman said: Baseline measurements have been made for natural methane seepage in the Denver-Julesburg (DJ) basin. See Etiope and Klusman, 2010, Microseepage in drylands: Implications in the global atmospherice source/sink budget of methane. Global Planetary Change, v. 72, pp. 265-274. doi:10.1016/jgloplacha. 2010.0.02. See the first line in Table 1. These measurements were made in 1994-95. See also Klusman references therein. The estimated natural seepage rate for methane is about 14^6 kg/year over the entire DJ basin. There are strong seasonalities with higher rates in the winter due to slowing of methanotrophic oxidation in the soil column.

2013-01-24 09:28 AM

steve aaron said: I think you may add to that list, the fact that Jaguar Landrover seems to think 70% annual growth in car sales to China is something to be proud of (and not at all unsustainable).

The fact that the growthmaniacs have appropriated â€˜sustainabilityâ€™ drives me spare. Communication is hard enough as i t is without shifting the damn goalposts.

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Regulatory Impact Analysis

Final 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

April 2012

CONTACT INFORMATION

This document has been prepared by staff from the Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency. Questions related to this document should be addressed to Alexander Macpherson, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, C445-B, Research Triangle Park, North Carolina 27711 (email: macpherson.alex@epa.gov).

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In addition to EPA staff from the Office of Air Quality Planning and Standards, personnel from the U.S. EPA Office of Atmospheric Programs, EC/R Incorporated, and ICF International contributed data and analysis to this document. Specific sections where EC/R Incorporated made contributions include the sections describing emissions options, pollution control options, secondary impacts analysis, engineering cost analysis, and employment impacts. Specific sections where ICF International made contributions also include the sections describing emissions options, pollution control options, engineering cost analysis, employment impacts, and small business impacts.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

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 rule 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 (VOC) from Natural Gas Processing Plants, and finalizes the NSPS for stationary sources in the source categories that are not covered by the existing NSPS. In addition, this rule 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 finalizes 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 annually. EPA estimates the final NSPS will have costs that exceed $100 million, so the Agency has prepared an RIA. Because the NESHAP Amendments are being finalized in the same rulemaking package (i.e., same Preamble), we have chosen to present the economic impact analysis for the final 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 final NSPS and NESHAP Amendments. We also estimate potential impacts of the final rules 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. The final NSPS contains provisions related to reduced emissions completions, pneumatic controllers, and storage vessels that phase-in emissions control requirements over time. As a result of these provisions, 2015 is the first year that the full requirements of the NSPS are in effect. Because of the phase-in provisions of the NSPS, the RIA does not present an accurate assessment of the period between promulgation and the end of 2014, but is accurate for 2015.

Several emission controls for the NSPS, such as reduced emissions completions (RECs) of hydraulically fractured natural gas wells, 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. RECs also recover saleable hydrocarbon condensates that 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 economic impact and energy economy analyses for the NSPS, we present results that include the additional product recovery and the revenues we expect producers to gain from the additional product recovery.

The primary baseline used for the impacts analysis of our NSPS for completions of hydraulically fractured natural gas wells takes into account RECs conducted pursuant to state regulations covering these operations and estimates of RECs performed voluntarily. To account for RECs performed in regulated states, EPA subsumed emissions reductions and compliance costs in states where these completion-related emissions are already controlled into the baseline. Additionally, based on public comments and reports to EPA's Natural Gas STAR program, EPA recognizes that some producers conduct well completions using REC techniques voluntarily for economic and/or environmental objectives as a normal part of business. To account for emissions reductions and costs arising from voluntary implementation of pollution controls EPA used information on total emissions reductions reported to the EPA by partners of the EPA Natural Gas STAR. This estimate of this voluntary REC activity in the absence of regulation is also included in the baseline.[1] More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket, as well as in Section 3 of this RIA.

[1] Voluntary short-term actions (such as REC) are challenging to capture accurately in a prospective analysis, as such reductions are not guaranteed to continue. However, Natural Gas STAR represents a nearly 20 year voluntary initiative with participation from 124 natural gas companies operating in the U.S., including 28 producers, over a wide historical range of natural gas prices. This unique program and dataset, the significant impact of voluntary REC on the projected cost and emissions reductions (due to significant REC activity), and the fact that RECs can actually increase natural gas recovered from natural gas wells (offering a clear incentive to continue the practice), led the Agency to conclude that it was appropriate to estimate these particular voluntary actions in the baseline for this rule.

Additionally, we provide summary-level estimates of emissions reductions and engineering compliance costs for a case where no voluntary RECs are assumed to occur. This alternative case is presented in order to show impacts if conditions were such that RECs were no longer performed on a voluntary basis, but rather were compelled by the regulation, and serves in part to capture the inherent uncertainty in projecting voluntary activity into the future. As such, this alternative case establishes the full universe of emissions reductions that are guaranteed by this NSPS (those that are *required* to occur under the rule, including those that would likely occur voluntarily). While the primary baseline may better represent actual costs (and emissions reductions) beyond those already expected under business as usual, the alternative case better captures the full amount of emissions reductions where the NSPS acts as a backstop to ensure that emission reduction practices occur (practices covered by this rule).

1.2 Summary of Results

1.2.1 NSPS Results

For the final NSPS, the key results of the RIA follow and are summarized in Table 1-1:

- **Benefits Analysis:** The final NSPS is anticipated to prevent significant new emissions, including 190,000 tons of VOC, as well as from 11,000 tons of hazardous air pollutants (HAP) and 1.0 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 HAP, ozone, and particulate matter (PM), we have determined that quantification of those benefits cannot be accomplished for this rule.[2] 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 final NSPS are likely to result in climate co-benefits. The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits, including an increase of 1.1 million tons of carbon dioxide (CO_2), 550 tons of nitrogen oxides (NOx), 19 tons of PM, 3,000 tons of CO, and 1,100 tons of total

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[2] Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the 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). 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 between VOC emissions and $PM_{2.5}$ and the highly localized nature of air quality responses associated with VOC reductions, 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.

hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent ($CO_{2\text{-}e}$) emission reductions are 18 million metric tons. If the EPA's estimate of voluntary action is not included in the NSPS baseline (only REC under state regulations are assumed to occur absent the NSPS), the emissions reductions achieved by the final NSPS in HAP, methane and VOC are estimated at about 19,000 tons, 1.7 million tons and 290,000 tons, respectively.

- **Engineering Cost Analysis:** EPA estimates the total capital cost of the final NSPS will be $25 million, regardless of baseline assumptions. The estimate of total annualized engineering costs of the final NSPS is $170 million. When estimated revenues from additional natural gas and condensate recovery are included, the annualized engineering costs of the final NSPS are estimated to be -$15 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 $43 million, given EPA estimates that 43 billion cubic feet of natural gas will be recovered by implementing the NSPS. If voluntary action is not deducted from the baseline, capital costs for the NSPS under the alternative regulatory baseline are estimated at $25 million, and annualized costs without revenues from product recovery for the NSPS are estimated at $330 million. In this scenario, given the assumptions about product prices, estimated revenues from product recovery are $350 million, yielding an estimated cost of savings of about $22 million. All estimates are in 2008 dollars.

- **Small Entity Analyses:** For the final NSPS, EPA performed a screening analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. When revenue from additional natural gas product recovered is not included, we estimate that 123 of the 127 small firms analyzed (96.9 percent) are likely to have impacts less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, four firms (3.1 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. However, when revenue from additional natural gas product recovery is included, we estimate that none of the analyzed firms will have an impact greater than 1 percent.

- **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 final NSPS is estimated at 50 full-time-equivalent employees. The annual labor requirement to comply with final NSPS is estimated at about 570 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to identify the specific number of people involved or whether new jobs are created for new employees, versus displacing jobs from other sectors of the economy.

Table 1-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Final Oil and Natural Gas NSPS in 2015[1]

	Final[4]
Total Monetized Benefits[2]	N/A
Total Costs[3]	-$15 million
Net Benefits	N/A
Non-monetized Benefits[6]	190,000 tons of VOC
	11,000 tons of HAP[5]
	1.0 million tons of methane[5]
	Health effects of HAP exposure[5]
	Health effects of $PM_{2.5}$ and ozone exposure
	Visibility impairment
	Vegetation effects
	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 HAP, 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.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the final 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 HAP and climate effects are co-benefits.

[6] The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits, including an increase of 1.1 million tons of carbon dioxide (CO_2), 550 tons of nitrogen oxides (NOx), 19 tons of PM, 3,000 tons of CO, and 1,100 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent ($CO_{2\text{-}e}$) emission reductions are 18 million metric tons.

1.2.2 NESHAP Amendments Results

For the final NESHAP Amendments, the key results of the RIA follow and are summarized in Table 1-2:

- **Benefits Analysis:** The final NESHAP Amendments are anticipated to reduce a significant amount of existing emissions, including 670 tons of HAP, as well as 1,200 tons of VOC and 420 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 HAP, 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.[3] In addition to health improvements, there will be improvements in visibility effects, ecosystem effects, and climate effects. The specific control technologies for the NESHAP are anticipated to have minor secondary disbenefits, but EPA was unable to estimate these secondary disbenefits. The net CO_2-equivalent emission reductions are about 8,000 metric tons.
- **Engineering Cost Analysis:** EPA estimates the total capital costs of the final NESHAP Amendments to be $2.8 million. Total annualized engineering costs, which includes annualized capital costs and operating and maintenance costs, of the final NESHAP Amendments are estimated to be $3.5 million. All estimates are in 2008 dollars.
- **Small Entity Analyses:** For the final NESHAP Amendments, EPA estimates that 11 of the 35 firms (31 percent) that own potentially affected facilities are small entities. The EPA performed a screening analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, none of the 11 (zero percent) are likely to have impacts of greater than 1 percent in terms of the ratio of annualized compliance costs to revenues.
- **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 final NESHAP Amendments is estimated at 4 full-time-equivalent employees. The annual labor requirement to comply with final NESHAP Amendments is estimated at about 30 full-time-equivalent employees. We note that this type of FTE estimate cannot be used to identify the specific

[3] Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the 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). 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 between VOC emissions and $PM_{2.5}$ and the highly localized nature of air quality responses associated with VOC reductions, 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.

number of people involved or whether new jobs are created for new employees, versus displacing jobs from other sectors of the economy.

- **Break-Even Analysis:** A break-even analysis suggests that HAP emissions would need to be valued at $5,200 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 $2,900 per ton or the methane emissions would need to be valued **a**t $8,300 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, 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 Final Oil and Natural Gas NESHAP in 2015[1]

	Final
Total Monetized Benefits[2]	N/A
Total Costs[3]	$3.5 million
Net Benefits	N/A
Non-monetized Benefits[5]	670 tons of HAP
	1,200 tons of VOC[4]
	420 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 HAP, 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.

[3] 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.

[5] The specific control technologies for the NESHAP are anticipated to have minor secondary disbenefits, but EPA was unable to estimate these secondary disbenefits. The net CO_2-equivalent emission reductions are 8,000 metric

tons.

1.2.3 Results of Energy System Impacts Analysis of the NSPS and NESHAP Amendments

The analysis of energy system impacts using NEMS for the final NSPS shows that domestic natural gas production is not likely to change in 2015, the year used in the RIA to analyze impacts. Average natural gas prices are also not estimated to change in response to the final rules. Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.01/barrel or about 0.01 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars.

1.2.4 Results for Combined Small Entity Analysis for the NSPS and NESHAP Amendments

After considering the economic impact of the combined NSPS and NESHAP Amendments on small entities, EPA certifies this action will not have a significant economic impact on a substantial number of small entities (SISNOSE). While both the NSPS and NESHAP amendment would individually result in a no SISNOSE finding, EPA performed an additional screening analysis in order to certify the rule in its entirety. This analysis compared compliance costs to entity revenues for the total of all the entities affected by the NESHAP Amendments and the sample of entities analyzed for the NSPS. When revenues from additional natural gas product sales are not included, 132 of the 136 small firms (97 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, four firms (3 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. When revenues from additional natural gas product sales are included, all 136 small firms (100 percent) in the sample are likely to have impacts of less than 1 percent.

1.3 Summary of NSPS Impacts Changes from the Proposal RIA

This section summarizes major changes from the proposal version of the RIA. These changes were a result of revised assumptions and technical factors, as well as changes in the rule itself from proposal.

- **Revised baseline to include voluntary RECs:** The NSPS analysis used a baseline that accounted for emission controls required by state regulation, but did not include voluntary actions. In the final RIA, to account for emissions reductions and costs arising in the baseline from voluntary implementation of pollution controls, EPA used information on total emissions reductions reported by partners of the EPA Natural Gas STAR. Additionally, we provide summary-level estimates of emissions reductions and engineering compliance costs for a case where no voluntary reduced emission completions (REC) are assumed to occur. This alternative case is presented in order to show impacts if conditions were such that RECs were no longer performed on a voluntary basis, but rather were compelled by the regulation.

- **Changed estimate of number of recompleted natural gas wells:** The NSPS proposal estimated that 12,050 RECs for existing natural gas well recompletions would be required in addition to those already required by state regulations. EPA has reevaluated the assumption based on data submitted to the Agency. Based on this information, EPA has estimated the recompletion frequency to be 1 percent of fractured gas wells per year, rather than 10 percent. More detailed discussion is presented in a technical memorandum on this subject in the docket.[4]
- **Recompletions of existing natural gas wells that are hydraulically refractured:** In the final rule, recompletions of existing natural gas wells that are hydraulically refractured are only subject to the NSPS if emissions from these completions are uncontrolled.
- **New hydraulically fractured natural gas well completions with insufficient pressure to implement REC required to combust completions emissions:** Using the formula estimated to identify hydraulically fractured natural gas well completions that would not have sufficient pressure to perform a REC, approximately 10 percent of well completions would be required to combust emissions rather than implement a REC. More detailed discussion is presented in a technical memorandum on this subject in the docket.[5]
- **Revised natural gas emissions factor for well completions and recompletions of hydraulically fractured wells:** The EPA received several comments regarding the emissions factor selected to calculate whole gas emissions (and the associated VOC emissions) from hydraulically fractured well completions. Comments focused on the data behind the emissions factor, what the emissions factor is intended to represent, and the procedures used to develop the emissions factor from the selected data sets. We reviewed all information received and have decided to retain the data set and the analysis conducted to develop the emissions factor, but rounded from 9,175 Mcf per completion

[4] "Gas Well Refracture Frequency" in U.S. Environmental Protection Agency Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

[5] "NSPS Low Pressure Completion Threshold" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

to 9,000 Mcf per completion. More detailed discussion is presented in a technical memorandum on this subject in the docket.[6]

- **Changed estimate of REC and completion emission combustion capital costs:** The requirements related to completions of hydraulically fractured natural gas wells (combustion and REC) are essentially one-shot events that typically occur over a few days to a couple of weeks and are generally performed by independent contractors. 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. Given that we base our REC costs estimates on the average cost for contracting the REC as a service, we expect contractors' operation and maintenance costs, depreciations, and potential salvage value of the equipment to be reflected in the total contracting costs. Because of these factors, we decided to treat the hydraulically fractured natural gas well completion requirements solely as annualized costs, which differed from our analysis at proposal, which equated capital and annualized costs.
- **Removal of compressors and pneumatic devices in the natural gas transmission segment from NSPS:** In the final rule, proposed requirements relating to reciprocating and centrifugal compressors and pneumatic devices in the transmission segment are removed. Given the large number of sources, and the relatively low level of VOCs emitted from these sources, we have concluded that additional evaluation of these compliance and burden issues is appropriate prior to taking final action on compressors and pneumatic controllers in the transmission and storage segment. Requirements pertaining to storage vessels in the transmission segment remain.
- **Reporting and recordkeeping costs**: EPA identified several ways to streamline reporting and recordkeeping requirements. As a result, the estimated annual cost of reporting and recordkeeping decreased from $19 million per year to $2.6 million per year.

1.4 Summary of NESHAP Amendments Impacts Changes from the Proposal RIA

The cost and emissions reduction estimates for the NESHAP Amendments are reduced from proposal because proposed provisions related to storage vessels were not finalized from proposal, as well as because of changes to the proposed provisions for small gycol dehydrators. The estimated capital costs of the NESHAP Amendments decreased by about $49 million (from $52 to about $3 million), while estimated total annualized compliance costs decreased by about $12.5 million per year (from $16 to $3.5 million per year) . As a result, estimated HAP reductions decreased by about 710 tons per year from proposal (from 1,380 to 670 tons per year).

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[6] "Evaluation of the Emissions factor for Hydraulically Fractured Gas Well Completions" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

Also, because of changes in emissions limits from proposal, fewer glycol dehydrators are affected, which reduces capital and annualized costs, as well as emissions reductions for these emissions points.

1.5 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 require 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 final 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 final 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 of total onshore natural gas production and nearly all 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 rule 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 dry natural gas proved reserves, inferred reserves, undiscovered technically recoverable resources and total technically recoverable resources as of 2007. According to EIA[7], 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.

According to EIA, dry natural gas is consumer-grade natural gas. The dry natural gas volumes reported in Table 2-1 reflect the amount of gas remaining after liquefiable portion has been removed from the natural gas, as well as any non-hydrocarbon gases that render the natural gas unmarketable have been removed. 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.

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[7] 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	385.0	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. While the dry natural gas proved reserves in 2007 were estimated at 237.7 tcf, wet natural gas reserves were estimated at 247.8 tcf. Of this difference, about 9.1 tcf is accounted for by natural gas liquids. Of the 247.8 tcf, 215.1 tcf (about 87 percent) is considered to be wet non-associated natural gas, while 32.7 tcf (about 13 percent) is considered to be wet associated-dissolved natural gas. Associated-dissolved natural gas, according to EIA, is natural gas which occurs in crude oil reservoirs as free natural gas or in solution with crude oil.

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.

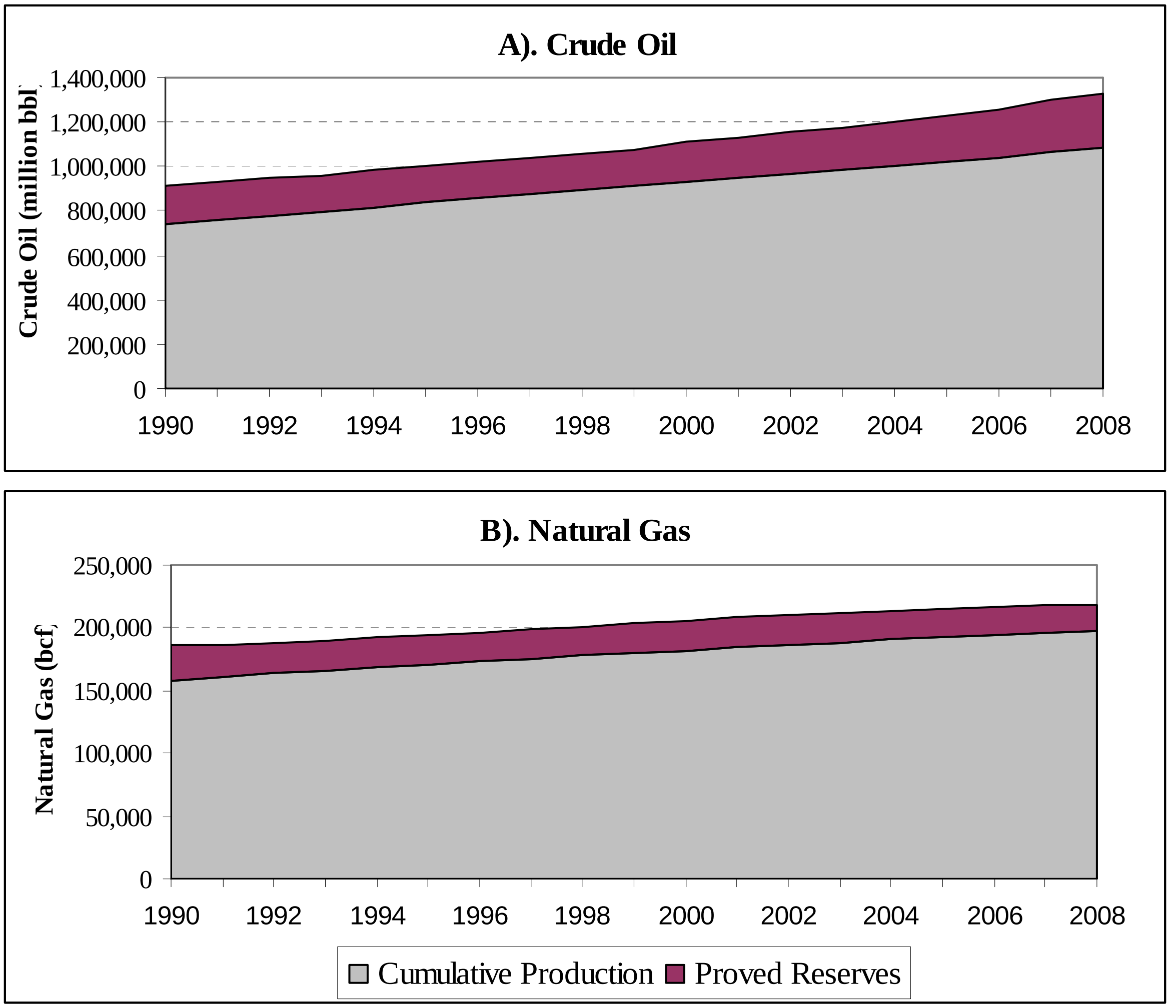

Figure 2-1 A) Domestic Crude Oil Proved Reserves and Cumulative Production, 1990-2008. B) Domestic Natural Gas Proved Reserves and Cumulative Production, 1990-2008

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.

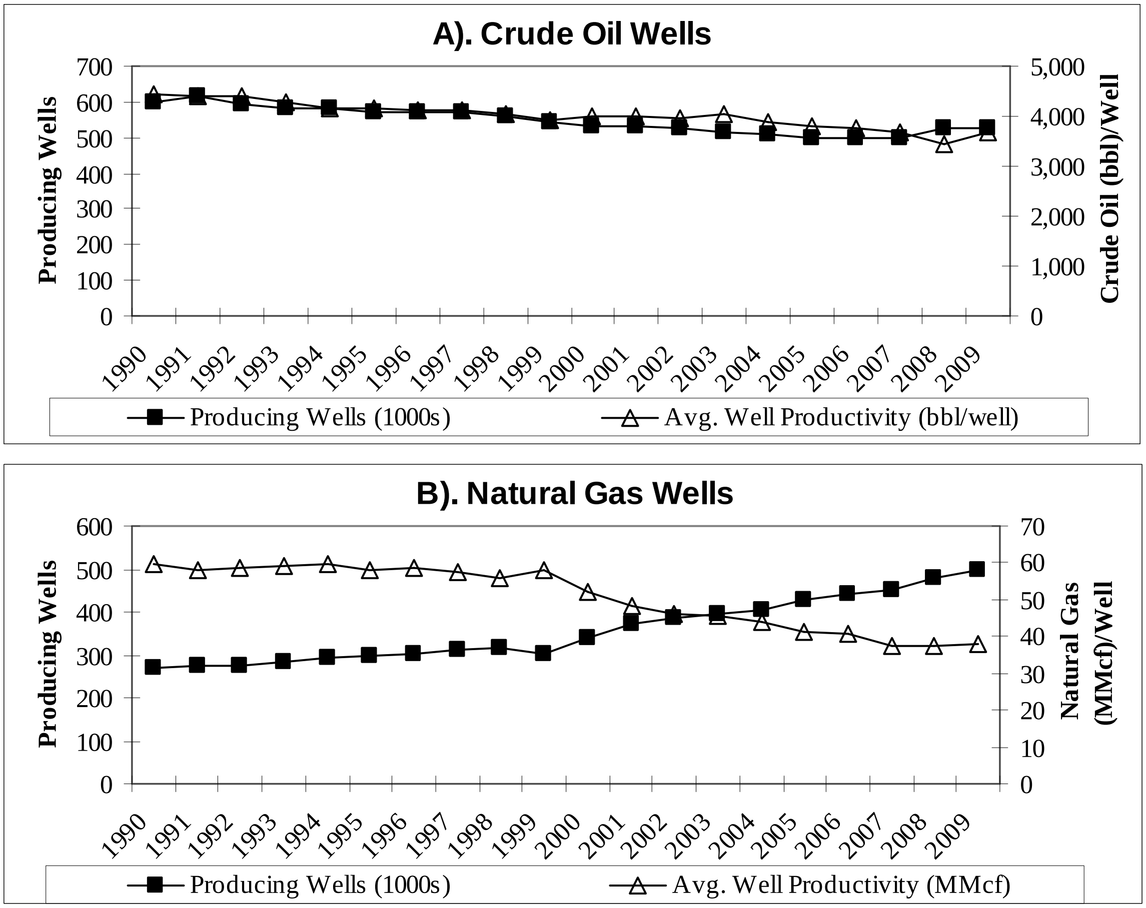

Figure 2-2 A) Total Producing Crude Oil Wells and Average Well Productivity, 1990-2009. B) Total Producing Natural Gas Wells and Average Well Productivity, 1990-2009.

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.

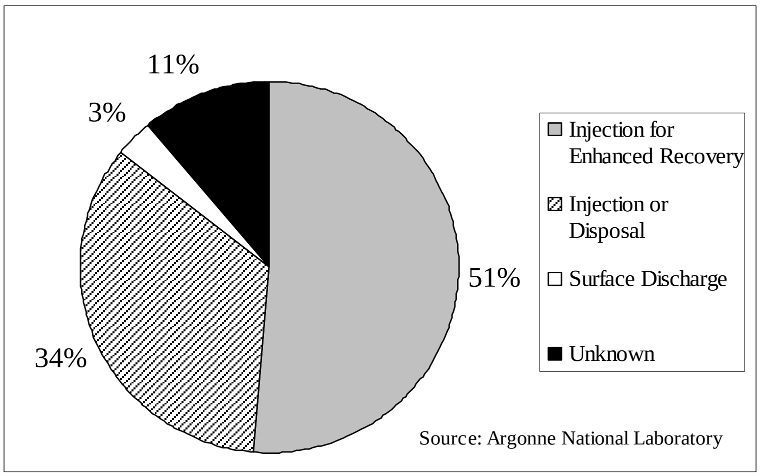

Figure 2-3 U.S. Produced Water Volume by Management Practice, 2007

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.

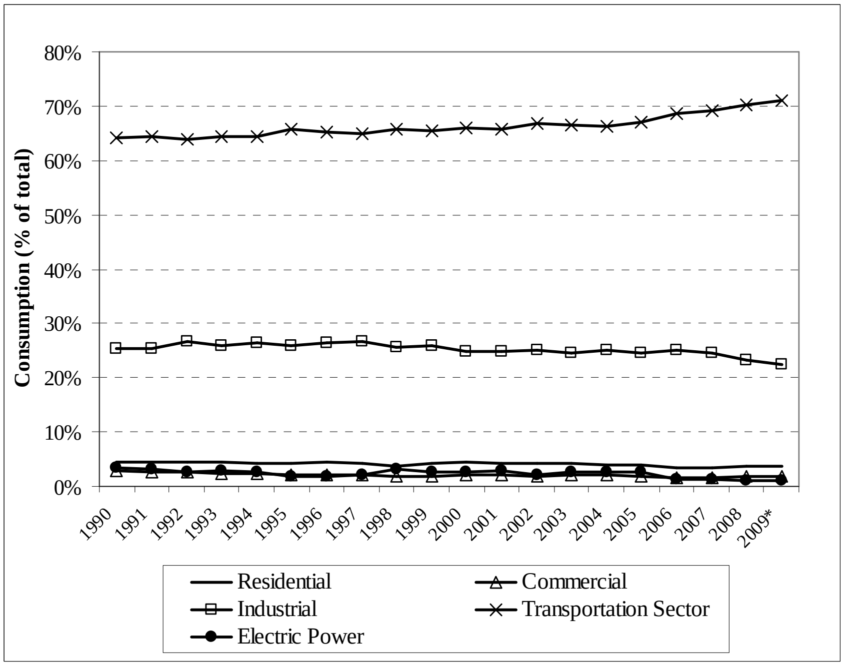

Figure 2-4 Crude Oil Consumption by Sector (Percent of Total Consumption), 1990-2009

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.

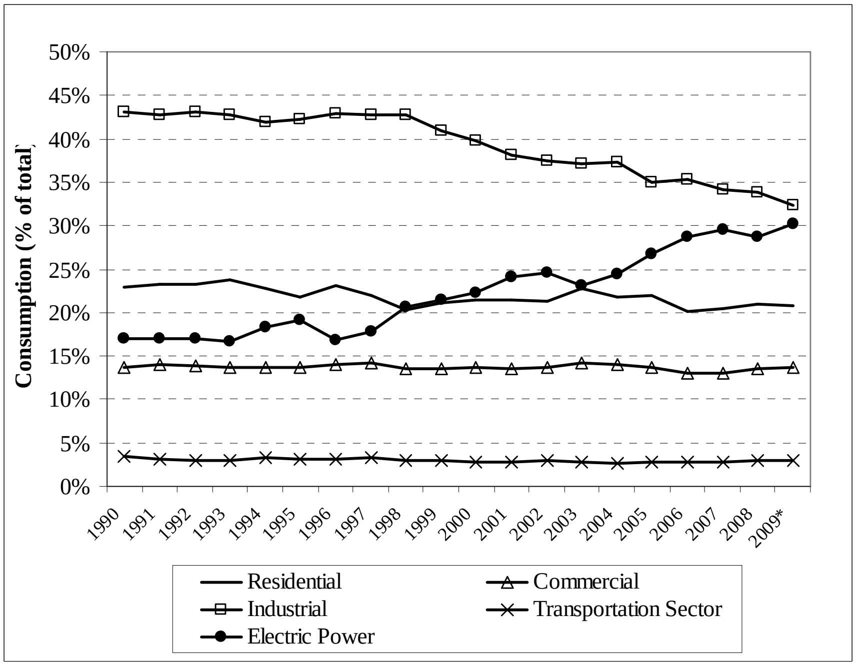

Figure 2-5 Natural Gas Consumption by Sector (Percent of Total Consumption), 1990-2009

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 final 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.

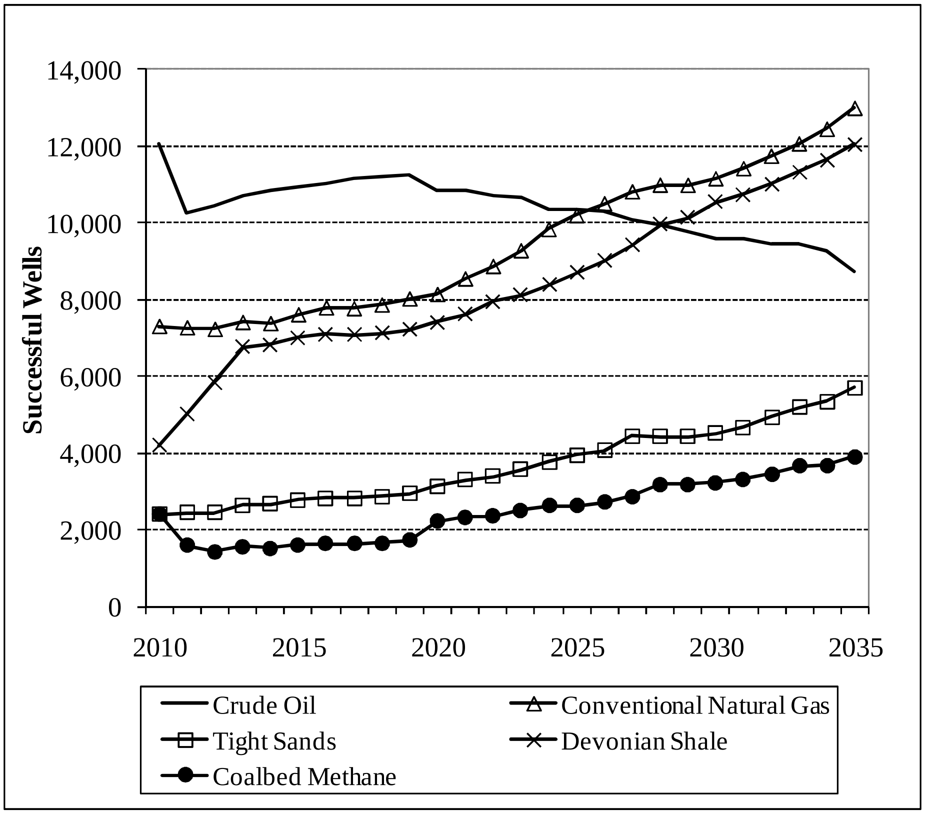

Figure 2-6 Forecast of Total Successful Wells Drilled, Lower 48 States, 2010-2035

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.

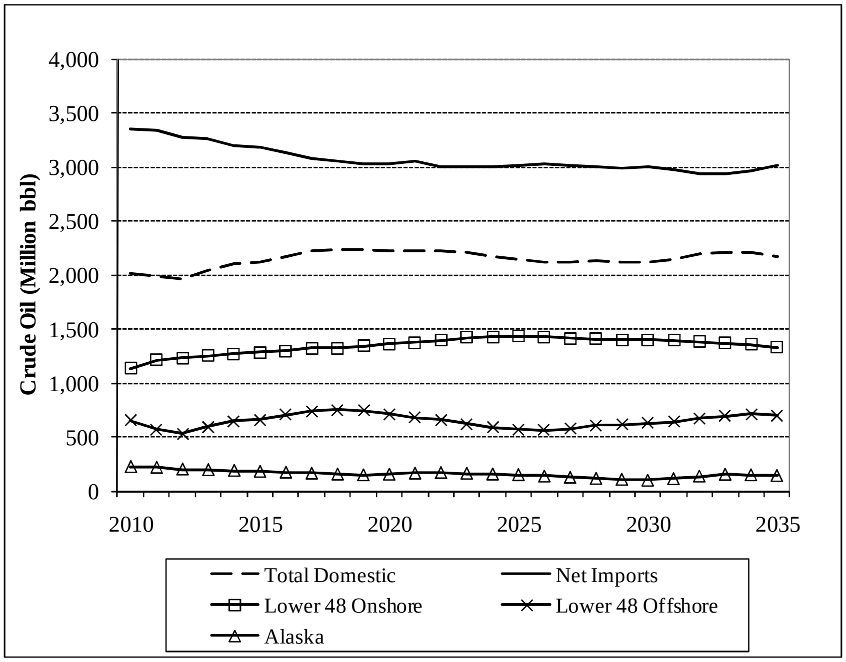

Figure 2-7 Forecast of Domestic Crude Oil Production and Net Imports, 2010-2035

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).

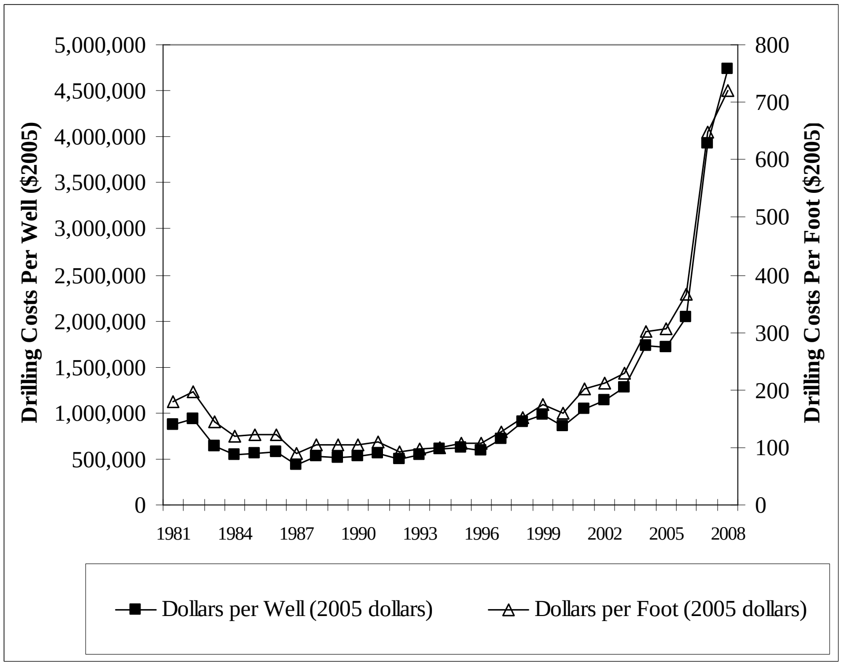

Figure 2-8 Costs of Crude Oil and Natural Gas Wells Drilled, 1981-2008

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.

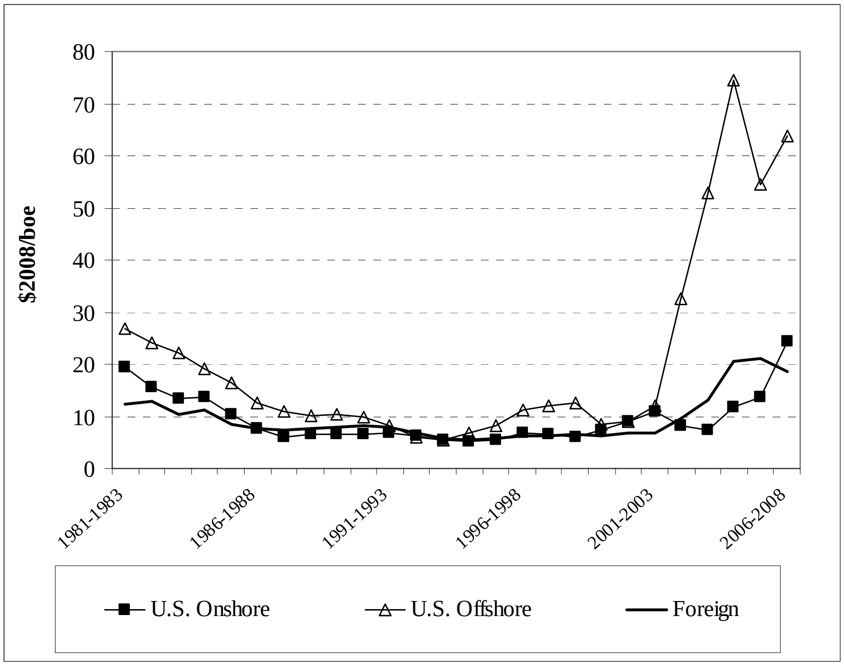

Figure 2-9 Finding Costs for FRS Companies, 1981-2008

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.

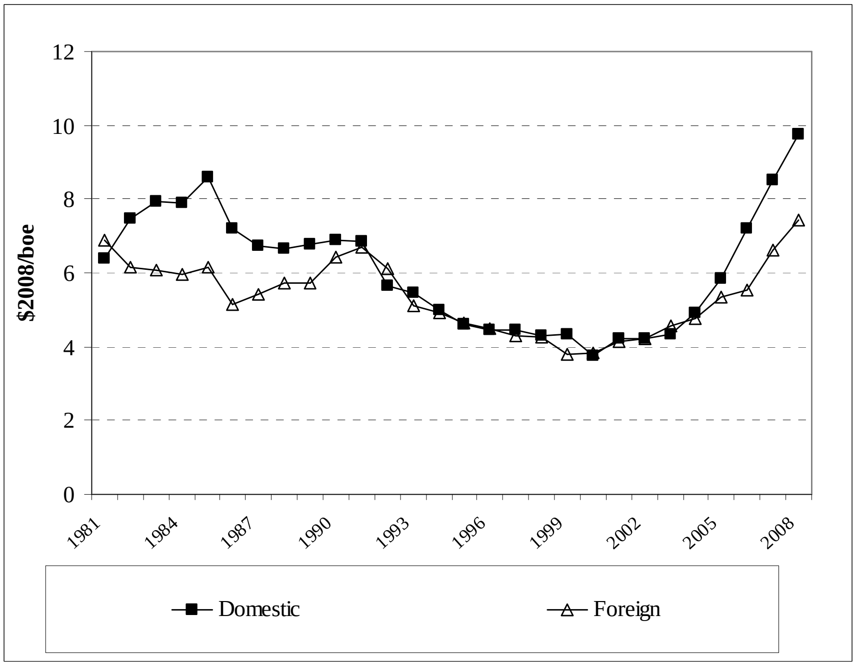

Figure 2-10 Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2008 (3-year Running Average)

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”[8], 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

[8] 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.

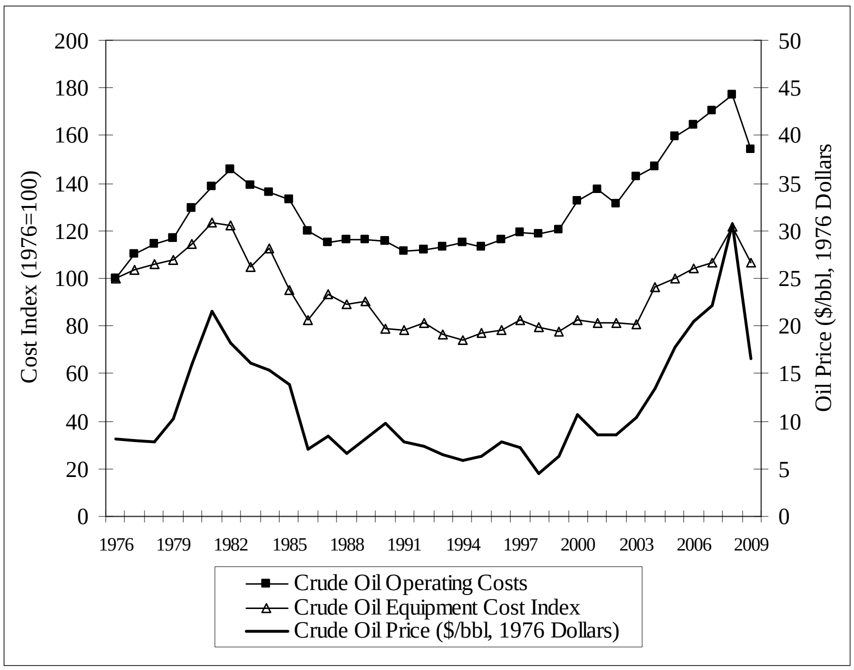

Figure 2-11 Crude Oil Operating Costs and Equipment Costs Indices (1976=100) and Crude Oil Price (in 1976 dollars), 1976-2009

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.

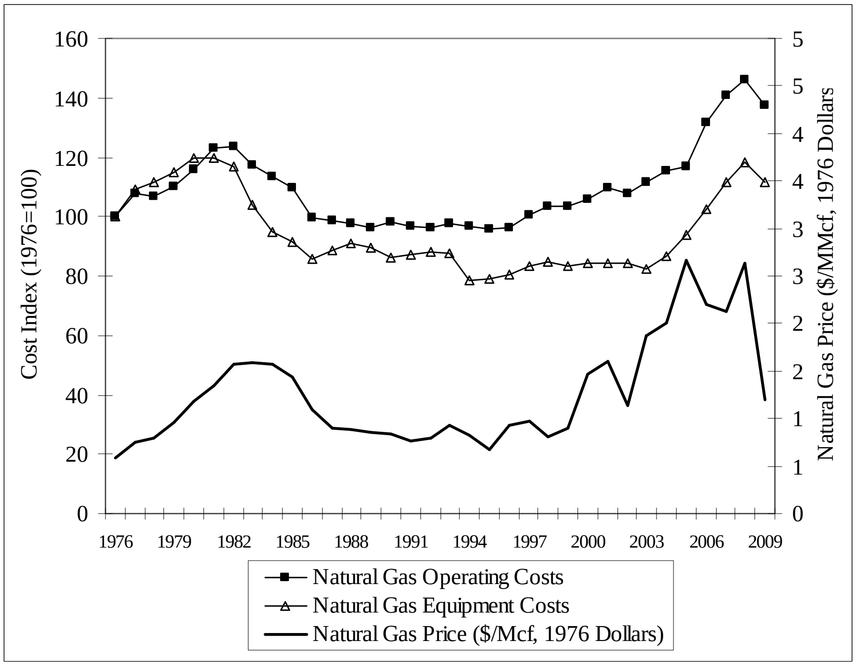

Figure 2-12 Natural Operating Costs and Equipment Costs Indices (1976=100) and Natural Gas Price, 1976-2009

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/>

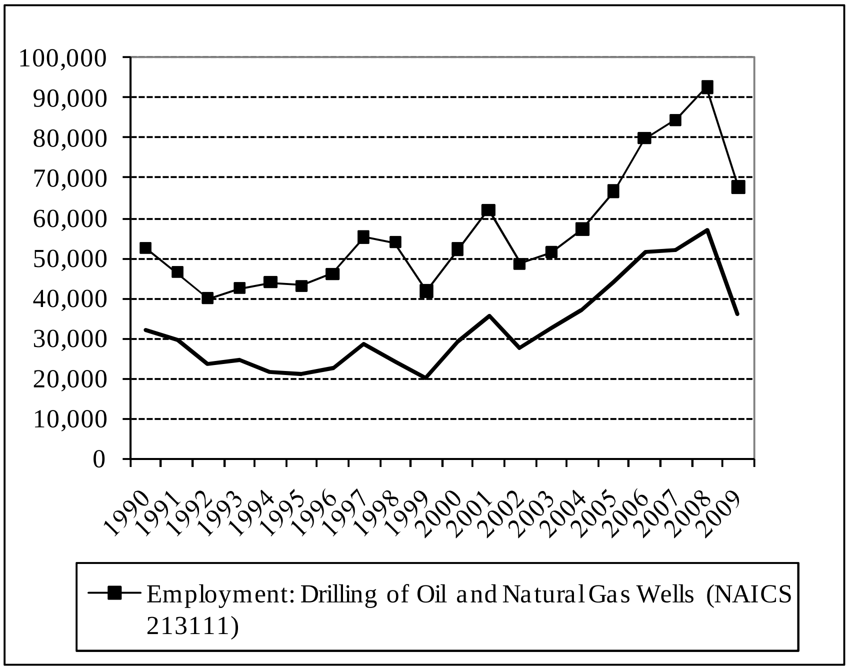

Figure 2-13 Employment in Drilling of Oil and Natural Gas Wells (NAICS 213111), and Total Oil and Natural Gas Wells Drilled, 1990-2009

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.

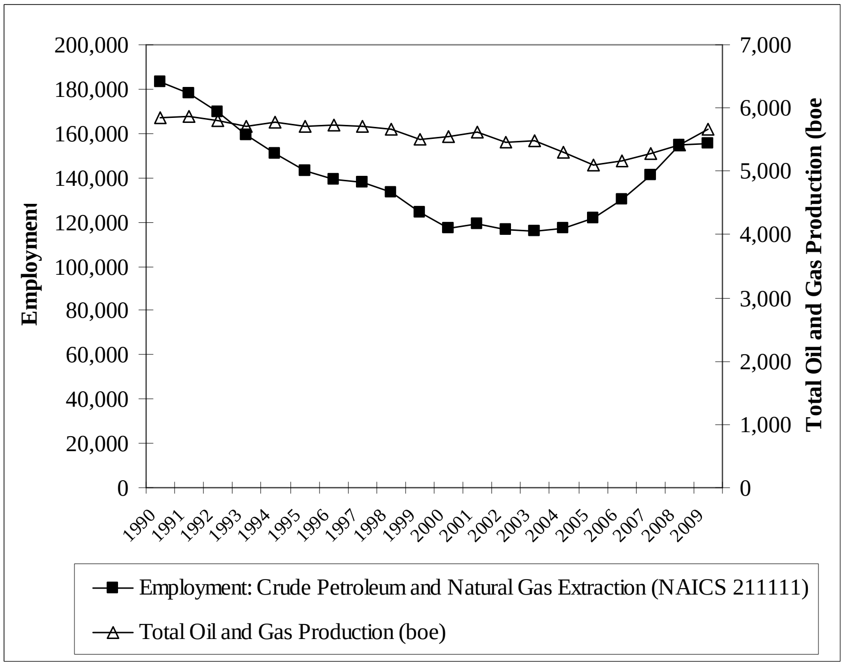

Figure 2-14 Employment in Crude Petroleum and Natural Gas Extraction (NAICS 211111) and Total Crude Oil and Natural Gas Production (boe), 1990-2009

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.

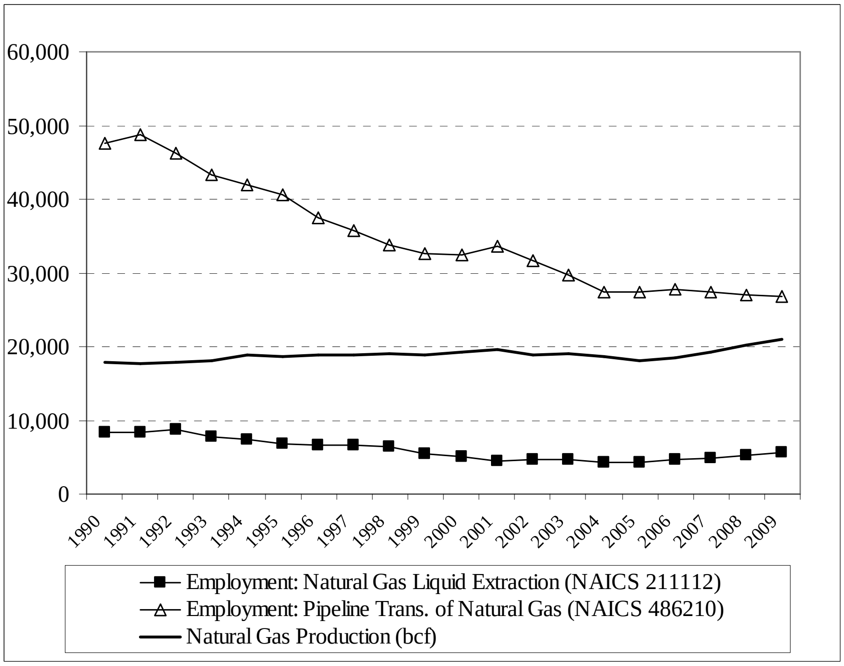

Figure 2-15 Employment in Natural Gas Liquid Extraction (NAICS 211112), Employment in Pipeline Transportation of Natural Gas (NAICS 486210), and Total Natural Gas Production, 1990-2009

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.

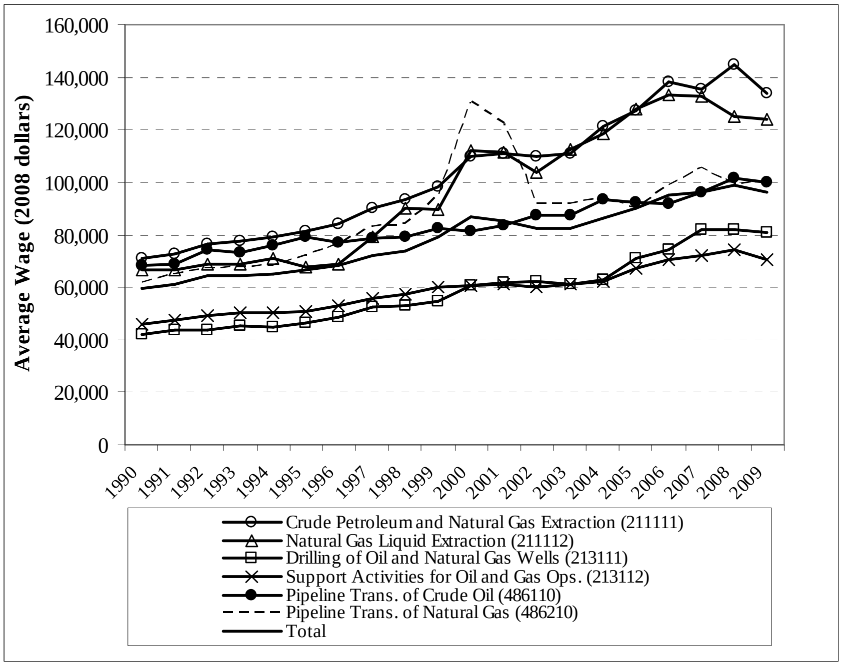

Figure 2-16 Oil and Natural Gas Industry Average Wages by NAICS, 1990-2009 ($2008)

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 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, all 137 public companies are listed.[9] Table 2-19 lists selected

[9] Oil and Gas Journal. “OGJ150 Financial Results Down in '09; Production, Reserves Up.” September 6, 2010.

statistics for 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 Liquids (Million bbl)	Worldwide Production Natural Gas (Bcf)	U.S. Production Liquids (Million bbl)	U.S. Production Natural Gas (Bcf)	Net Wells Drilled
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[10] 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.

[10] 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 final 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 final 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, 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 gas industry to provide context for estimated reductions as a result of the final rules. 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 that 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 (132,000 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 1.87 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 analysis 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 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 proposal Technical Support Document (TSD) and Background Supplemental Technical Support Document for the Final New Source Performance Standards, which are published in the Docket. Technical memos that also discuss revisions to the proposal TSD are noted in the relevant sections.

Centrifugal and reciprocating compressors [11]**:** 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

[11] "Centrifugal Compressor Impacts" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

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: 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 the 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: 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[12]: 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

[12] "Update to Technical Support Document for Proposed Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution- Equipment Leaks" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

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 production 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 emissions 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: 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 natural 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 natural gas completions involving hydraulic fracturing vent substantially more natural gas, approximately 230 times more, than natural gas completions not involving hydraulic fracturing. Specifically, we estimate that uncontrolled natural gas well completion emissions for a hydraulically fractured natural gas well are about 23 tons of VOC, where emissions for a conventional natural gas well completion are around 0.1 ton of VOC. Our data indicate that hydraulically fractured natural gas wells have higher emissions but we believe some natural gas wells that are not hydraulically fractured may have higher emissions than our data show, or in some cases, hydraulically fractured natural gas wells could have lower emissions than 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 natural gas so it can be directed into the sales line and avoid emissions from venting. Equipment required to conduct a reduced emissions completion at a natural gas well may include tankage, special gas-liquid-sand separator traps, and gas dehydration. Equipment costs associated with reduced emission completions of natural gas wells will vary from well to well. Based on information provided to the EPA Natural Gas STAR program, 90 percent of natural 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 final 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[13]: 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 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 (1) to 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

[13]Memorandum from Brown, H., EC/R Incorporated to Moore, B., and Nizich, G., EPA/OAQPS/SPPD/FIG. Impacts of Final MACT Standards for Glycol Dehydration Units – Oil and Natural Gas Production and Natural Gas Transmission and Storage Source Categories. April 17, 2012.

emission reduction efficiency by reducing the concentration of non-condensable gases present in the stream prior to being introduced into the condenser.

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 final NSPS and NESHAP Amendments. A detailed discussion of the methodology used to estimate cost impacts is presented in a 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 the analysis supporting the proposed and final rules. The final NSPS contains reduced emission completion (REC) and completion combustion requirements for a subset of newly drilled natural gas wells that are hydraulically fractured. The NSPS also requires a subset of natural gas wells that are recompleted using hydraulic fracturing to implement a REC and emissions combustion. The NSPS requires emissions reductions from reciprocating compressors at gathering and boosting stations and processing plants. The NSPS also requires emissions reductions from centrifugal compressors at processing plants. Finally, the NSPS requires emissions reductions from pneumatic controllers at oil and gas production facilities and reductions from storage vessels that emit at least six tons of VOC per year.

Table 3-1 Emissions Sources, Points, and Controls Evaluated at Proposal for the NSPS

Emissions Sources and Points	Emissions Control	Covered by Final NSPS
Crude Oil and Natural Gas Well Completions		
Hydraulically Fractured Gas Wells that Meet Criteria for Reduced Emissions Completion (REC)	REC/Combustion	**X**
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC	Combustion	**X**
Conventional Gas Wells	Combustion	
Oil Wells	Combustion	
Crude Oil and Natural Gas Well Recompletions		
Hydraulically Refractured Gas Wells that Meet Criteria for Reduced Emissions Completion (REC)	REC/Combustion	**X**
Hydraulically Refractured Gas Wells that Do Not Meet Criteria for REC	Combustion	**X**
Conventional Gas Wells	Combustion	
Oil Wells	Combustion	
Equipment Leaks		
Well Pads	NSPS Subpart VV	
Gathering and Boosting Stations	NSPS Subpart VV	
Processing Plants	NSPS Subpart VVa	**X**
Transmission Compressor Stations	NSPS Subpart VV	
Reciprocating Compressors		
Well Pads	Annual Monitoring/ Maintenance (AMM)	
Gathering and Boosting Stations	AMM	**X**
Processing Plants	AMM	**X**
Transmission Compressor Stations	AMM	
Underground Storage Facilities	AMM	
Centrifugal Compressors		
Processing Plants	Route to control	**X**
Transmission Compressor Stations	Route to control	
Pneumatic Controllers -		
Oil and Gas Production	Emissions limit	**X**
Natural Gas Transmission and Storage	Emissions limit	
Processing Plants	Emissions limit	**X**
Storage Vessels		
Emissions at least 6 tons per year	95% control	**X**
Emissions less than 6 tons per year	95% control	

As discussed in the Executive Summary, several emission controls for the NSPS, such as reduced emissions completions (RECs) of hydraulically fractured natural gas wells, 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. RECs also recover saleable hydrocarbon condensates that 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 economic impact and energy economy analyses for the NSPS, we present results that include the additional product recovery and the revenues we expect producers to gain from the additional product recovery.

The primary baseline used for the impacts analysis of our NSPS for completions of hydraulically fractured natural gas wells takes into account RECs conducted pursuant to state regulations covering these operations and estimates of RECs performed voluntarily. To account for RECs performed in regulated states, EPA subsumed emissions reductions and compliance costs in states where these completion-related emissions are already controlled into the baseline. Additionally, based on public comments and reports to EPA's Natural Gas STAR program, EPA recognizes that some producers conduct well completions using REC techniques voluntarily for economic and/or environmental objectives as a normal part of business. To account for emissions reductions and costs arising from voluntary implementation of pollution controls EPA used information on total emissions reductions reported to the EPA by partners of the EPA Natural Gas STAR. This estimate of this voluntary REC activity in the absence of regulation is therefore also in the baseline.[14] More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket, as well as in the RIA.

[14] Voluntary short-term actions (such as REC) are challenging to capture accurately in a prospective analysis, as such reductions are not guaranteed to continue. However, Natural Gas STAR represents a nearly 20 year voluntary initiative with participation from 124 natural gas companies operating in the U.S., including 28 producers, over a wide historical range of natural gas prices. This unique program and dataset, the significant impact of voluntary REC on the projected cost and emissions reductions (due to significant REC activity), and the fact that RECs can actually increase natural gas recovered from natural gas wells (offering a clear incentive to continue the practice), led the Agency to conclude that it was appropriate to estimate these particular voluntary actions in the baseline for this rule.

Additionally, in the RIA, we provide summary-level estimates of emissions reductions and engineering compliance costs for a case where no voluntary RECs are assumed to occur. This alternative case is presented in order to show impacts if conditions were such that RECs were no longer performed on a voluntary basis, but rather were compelled by the regulation, and serves in part to capture the inherent uncertainty in projecting voluntary activity into the future. As such, this alternative case establishes the full universe of emissions reductions that are guaranteed by this NSPS (those that are *required* to occur under the rule, including those that would likely occur voluntarily). While the primary baseline may better represent actual costs (and emissions reductions) beyond those already expected under business as usual, the alternative case better captures the full amount of emissions reductions where the NSPS acts as a backstop to ensure that emission reduction practices occur (practices covered by this rule).

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 Docket, as referenced in Section 3.2.1 of this RIA. The table also includes the number of affected units projected under the primary baseline and the alternative regulatory baseline. Four issues are important to note regarding engineering compliance cost estimates: the approach to annualizing costs, the projection of affected units in the baseline; that estimate rental costs are used 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.

Table 3-2 Summary of Projected No. of Affected Units Under Primary and Alternative Regulatory Baselines and Capital and Annualized Costs per Unit for Final NSPS Emissions Sources and Points

	Projected No. of Affected Units			Annualized Cost (2008$)	
Source/Emissions Point	Primary Baseline	Alternative Regulatory Baseline	Capital Costs (2008$)	Without Rev. from Addl. Product Recovery	With Rev. from Addl. Product Recovery
Hydraulically Fractured Natural Gas Well Completions					
Hydraulically Fractured Gas Wells that Meet Criteria for REC	4,107	8,382	$0	$33,237	-$1,543
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	1,377	1,377	$0	$3,523	$3,523
Hydraulically Refractured Natural Gas Well Completions					
Hydraulically Refractured Gas Wells that Meet Criteria for REC	532	1,085	$0	$33,237	-$1,543
Hydraulically Refractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	121	121	$0	$3,523	$3,523
Equipment Leaks					
Processing Plants	29	29	$8,041	$12,273	$8,474
Reciprocating Compressors					
Gathering and Boosting Stations	210	210	$5,346	$2,456	$870
Processing Plants	209	209	$4,050	$2,090	-$2,227
Centrifugal Compressors					
Processing Plants	13	13	$22,000	$3,132	-$46,974
Pneumatic Controllers					
Oil and Gas Production	13,632	13,632	$165	$23	-$1,519
Processing Plants	15	15	$16,972	$11,090	$7,606
Storage Vessels					
Emissions at least 6 tons per year	304	304	$65,243	$19,864	$19,281

3.2.2.1.1 Approach to Annualizing Engineering Compliance Costs

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)
- 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. This approach is mathematically equivalent to establishing an overall, representative project time horizon and annualizing 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.

3.2.2.1.2 Projection of Affected Units

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. In the National Energy Modeling System (NEMS) used by the EIA to produce the Annual Energy

Outlook identifies wells as being either a natural gas well or oil well. No criteria, such as a gas-oil ratio, for example, are applied within the model to a well to determine whether it is a natural gas well or an oil well. Additionally, EIA uses historical information as data for the NEMS. To collect these data, EIA relies upon States to submit information. States submit information about natural gas wells and oil wells based upon state-level approaches to classification, which varies greatly across States. In most instances, no national-level criteria are applied to reclassify the State-submitted information. To the extent that EPA's definition of a natural gas well differs from the various definitions used by States, potential differences in definitions may explain some difference between forecast impacts of the NSPS and the true costs incurred once the NSPS is implemented.

To approximate the number of natural gas wells that would not be required to combust emissions rather than perform a REC because they are wildcat (exploratory) and delineation wells, we draw upon the distinction in the EIA's analysis between exploratory and developmental wells. EIA defines an exploratory well as a "hole drilled a) to find and produce oil or gas in an area previously considered unproductive area; b) to find a new reservoir in a known field, i.e., one previously producing oil and gas from another reservoir, or c) to extend the limit of a known oil or gas reservoir." According to EIA, a "development well is a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive." [15] The definitions of exploratory and developmental wells do not take into account whether the wells primarily produce crude oil or natural gas. For the impacts analysis, we assume exploratory wells as defined and estimated by EIA are equivalent to the NSPS-affected wildcat (exploratory) and delineation wells described in the NSPS as requiring to combust completion emissions rather than perform a REC.

The number of hydraulically fractured recompletions of existing wells was approximated using assumptions found in Subpart W's TSD[16] and applied to well count data found in the proprietary HPDI® database. The underlying assumption is that wells found in coal bed

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[15] Source: 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.

[16] 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, one 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, as well as information reported to the EPA's Natural Gas STAR program. Based on the criterion relating to State regulations, 15 percent of natural gas completions with hydraulic fracturing and 15 percent of recompletions of existing natural gas workovers with hydraulic fracturing are estimated to be controlled by either flare or REC in absence of Federal regulations. EPA does not have comprehensive information on the number of hydraulically fractured natural gas well completions that might be required by state or local regulations to combust completion emissions, which upon promulgation of this rule will be required to perform a REC. Based on the criterion relating to voluntary REC implementation, 51 percent of the completions and recompletions outside of regulated States are assumed to have been performed using a REC.

However, because the pressure level for some wells may be insufficient to successfully perform a REC, these wells will be required to combust emissions, rather than implement a REC. EPA analysis shows about 10 percent of the wells that otherwise would be required by the NSPS to perform a REC will combust emissions.

Table 3-3 Estimated New Hydraulically Fractured and Refractured Natural Gas Well Completions Affected by NSPS, 2015

	Hydraulically Fractured Natural Gas Well Completions of New Wells	Hydraulically Refractured Natural Gas Well Completions of Existing Wells
Nationwide Hydraulically Fractured Natural Gas Well Completions	11,403[1]	1,417[2]
Completions Exempt from NSPS REC Requirement		
Wildcat (Exploration Wells) and Delineation[1]	*446*	*0*
Low Pressure[3]	*931*	*121*
RECs Performed Absent Federal Regulation		
REC Already Required by States	*1,644*	*212*
Voluntarily Performed RECs Outside of Regulated States[4]	*4,275*	*553*
Total RECs Incrementally Required by NSPS	**4,107**	**532**
Total Completion Combustion Incrementally Required by NSPS	**1,377**	**121**

Note: sums may not total because of independent rounding.

1 Annual Energy Outlook 2011 Reference Case (successful completions in tight sands, shale, coalbed methane formations in 2015)

2 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. Also reflects revised assumptions regarding refracture frequency.

3 "NSPS Low Pressure Completion Threshold" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

4 "Voluntary Reductions from Gas Well Completions with Hydraulic Fracturing" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

Table 3-3 presents the accounting used for the estimate of the number of hydraulically fractured natural gas completions incrementally affected by the NSPS, after accounting for State regulation and voluntary action. In summary, we estimate 4,107 completions of new hydraulically fractured natural gas wells and 531 existing hydraulically refractured natural gas wells will incrementally be required to perform a REC in 2015. Additionally, we estimate 1,377 completions of new hydraulically fractured natural gas wells and 121 existing hydraulically refractured natural gas wells will be incrementally required to combust emissions in 2015. The methods to derive these figures are detailed in a technical memo in the Docket.[17]

It also 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 REC that capture emissions over short periods of time.

3.2.2.1.3 REC Unit Rental Costs

The completion requirements (combustion and REC) are essentially one-shot events and are generally performed by independent contractors. 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, if at all. After the completion is concluded, the REC equipment is typically moved by contractors to be reused during other well completions. Given that we base our REC costs on the average cost for contracting the REC as a service, we expect contractors' operation and maintenance costs, depreciations, and potential salvage value of the equipment to be reflected in the total contracting costs. Because of these factors, we decided to treat the hydraulically fractured natural gas well completion requirements solely as annualized costs.

3.2.2.1.4 Revenues from Natural Gas Product Recovery

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 from 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 VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams

[17] "National Impacts of the NSPS OOOO Requirements on Gas Well Completions" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

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. For the RIA, in the case of a REC, the revenues from captured and sold natural gas products are assumed to accrue in the same year as the REC is performed and only that year. For other environmental controls that avert the emission of saleable natural gas, such as pneumatic controllers, we base the estimated revenues from averted natural gas emissions on an estimate of the amount of natural gas that would not be emitted during one year for the control.

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 $43 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 3-4 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 annual reporting and recordkeeping costs for the final NSPS are estimated at $2.6 million per year and are included in Table 3-4.

As can be seen from Table 3-4, which presents estimates, under the primary baseline, of nationwide compliance costs, emissions reductions, and VOC reduction cost-effectiveness from controls associated with well completions and recompletions, hydraulically fractured natural gas wells provide the largest potential for emissions reductions from evaluated emissions sources and points. Controlling equipment leaks at processing plants presents the most significant compliance costs if revenue from additional natural gas recovery is not included. Table 3-5 presents the same set of information under the alternative regulatory baseline.

Several evaluated emissions sources and points are estimated to have net financial savings when including the revenue from additional natural gas recovery. Table 3-6 presents the estimated engineering costs, emissions reductions, and VOC reduction cost-effectiveness for the final NSPS under the primary baseline. The resulting total national annualized cost impact of the final NSPS rule is estimated at $170 million per year without considering revenues from additional natural gas recovery. Total national annualized costs for the final NSPS are estimated at -$15 million when revenue from additional natural gas recovery is included. All figures are in 2008 dollars.

Table 3-4 Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by NSPS Emissions Sources and Points, Primary Baseline, 2015

Source/Emissions Point	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
Hydraulically Fractured Natural Gas Well Completions							
Hydraulically Fractured Gas Wells that Meet Criteria for REC	$136,511,391	-$6,336,330	88,305	605,244	6,416	$1,546	-$72
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	$4,850,956	$4,850,956	29,606	202,918	2,151	$164	$164
Hydraulically Refractured Natural Gas Well Completions							
Hydraulically Refractured Gas Wells that Meet Criteria for REC	$17,682,220	-$820,740	11,438	78,397	831	$1,546	-$72
Hydraulically Refractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	$426,264	$426,264	2,602	17,831	189	$164	$164
Equipment Leaks							
Processing Plants	$355,917	$245,746	132	475	5	$2,693	$1,860
Reciprocating Compressors							
Gathering and Boosting Stations	515,764	182,597	400	1,437	15	$1,291	$457
Processing Plants	436,806	-465,354	1,082	3,892	41	$404	-$430
Centrifugal Compressors							
Processing Plants	$40,720	-$610,657	254	2,810	9	$161	-$2,408
Pneumatic Controllers							
Oil and Gas Production	$320,071	-$20,699,918	25,210	90,685	952	$13	-$821
Processing Plants	$166,351	$114,094	63	225	2	$2,659	$1,824
Storage Vessels							
Emissions at least 6 tons per year	$6,031,787	$5,855,032	29,654	6,490	876	$203	$197
Reporting and Recordkeeping	2,576,065	2,576,065	N/A	N/A	N/A	N/A	N/A
TOTAL	**$169,914,312**	**-$14,682,245**	**188,744**	**1,010,405**	**11,487**	**$900**	**-$78**

Table 3-5 Estimated Nationwide Compliance Costs, Emissions Reductions, and VOC Reduction Cost-Effectiveness by NSPS Emissions Sources and Points, Alternative Regulatory Baseline, 2015

	Nationwide Annualized Costs (2008$)		Nationwide Emissions Reductions (tons/year)			VOC Emissions Reduction Cost-Effectiveness (2008$/ton)	
Source/Emissions Point	**Without Addl. Revenues**	**With Addl. Revenues**	**VOC**	**Methane**	**HAP**	**Without Addl. Revenues**	**With Addl. Revenues**
Hydraulically Fractured Natural Gas Well Completions							
Hydraulically Fractured Gas Wells that Meet Criteria for REC	$278,594,675	-$12,931,285	180,214	1,235,192	13,093	$1,546	-$72
Hydraulically Fractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	$4,850,956	$4,850,956	29,606	202,918	2,151	$164	$164
Hydraulically Refractured Natural Gas Well Completions							
Hydraulically Refractured Gas Wells that Meet Criteria for REC	$36,062,422	-$1,673,878	$23,328	$159,888	$1,695	$1,546	-$72
Hydraulically Refractured Gas Wells that Do Not Meet Criteria for REC (Completion Combustion)	$426,264	$426,264	$2,602	$17,831	$189	$164	$164
Equipment Leaks							
Processing Plants	$355,917	$245,746	$132	$475	$5	$2,693	$1,860
Reciprocating Compressors							
Gathering and Boosting Stations	$515,764	$182,597	$400	$1,437	$15	$1,291	$457
Processing Plants	$436,806	-$465,354	$1,082	$3,892	$41	$404	-$430
Centrifugal Compressors							
Processing Plants	$40,720	-$610,657	$254	$2,810	$9	$161	-$2,408
Pneumatic Controllers							
Oil and Gas Production	$320,071	-$20,699,918	$25,210	$90,685	$952	$13	-$821
Processing Plants	$166,351	$114,094	$63	$225	$2	$2,659	$1,824
Storage Vessels							
Emissions at least 6 tons per year	$6,031,787	$5,855,032	$29,654	$6,490	$876	$203	$197
Reporting and Recordkeeping	$2,576,065	$2,576,065	N/A	N/A	N/A	N/A	N/A
TOTAL	**$330,377,798**	**-$22,130,338**	**292,543**	**1,721,844**	**19,029**	**$1,129**	**-$76**

Table 3-6 Engineering Compliance Costs, Emission Reductions, and Cost-Effectiveness, Primary Baseline, NSPS (2008$)

	Final NSPS
Capital Costs	$24,803,968
Annualized Costs	
Without Revenues from Additional Natural Gas Product Recovery	$169,914,312
With Revenues from Additional Natural Gas Product Recovery	-$14,682,245
VOC Reductions (tons per year)	188,744
Methane Reduction (tons per year)	1,010,405
HAP Reductions (tons per year)	11,487
VOC Reduction Cost-Effectiveness ($/ton without additional product revenues)	$900
VOC Reduction Cost-Effectiveness ($/ton with additional product revenues)	-$78

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 $43 million in 2008 dollars. The annualized cost estimates also include reporting and recordkeeping costs of $2.6 million.

As shown in Table 3-5, if voluntary action is not subsumed into the NSPS baseline, the emissions reductions achieved by the final NSPS are estimated at about 290,000 tons VOC, 19,000 tons HAP, and 1.7 million tons methane, and annualized costs without revenues from product recovery are estimated at $330 million. In this scenario, given the assumptions about product prices, estimated revenues from product recovery are $350 million, yielding an estimated cost of savings of about $22 million.

As assumptions about natural gas prices, REC costs, and the potential emissions from hydraulically fractured natural gas well completions are influential on estimated impacts, we performed a pair of simple sensitivity analyses of the influence of these factors on the engineering costs estimate of the final NSPS. To perform this analysis, we vary the national average wellhead natural gas price from $2/Mcf to $7/Mcf while, first, varying REC costs and, second, varying the natural gas emissions that are captured by implementing a REC.

To characterize variation in REC costs, we use the data reported in the proposal TSD that were used to estimate the national average cost of performing a REC. On the low end of the range, we assume a REC costs $806 per day. This represents completion and recompletion costs where key pieces of equipment, such as a dehydrator or three phase separator, are already found on site and are of suitable design and capacity for use during flowback. On the upper end of the range, we use $7,486 per day, which represents the cost in situations where key pieces of equipment, such as a dehydrator or three-phase separator, are temporarily brought on site and then relocated after the completion. Like the primary analysis of the NSPS cost impacts, we use the average of these two values, $4,146 per day, to represent a mid-range case. Also like the primary NSPS impacts analysis, each REC also incurs include transportation and setup costs of $691 and completion combustion costs of $3,523 and assume an average flowback period of seven days. In sum, the low, average, and high REC costs are estimated at $9,856, $33,237, and $56,616, respectively.

For the mean estimate of the potential emissions from hydraulically fractured natural gas well completions, we use the 9,000 Mcf per completion which is used in the primary impacts analysis. To characterize the variation in potential natural gas emissions, we use the low and high ends of the 95 confidence interval around this mean estimate presented in a supporting technical memo.[18] The low-end estimate of potential emissions from hydraulically fractured natural gas well completions is estimated at 6,100 Mcf per completion and the high end at 11,700 Mcf per completion.

It is important to note two caveats to the analysis. First, while the gas price is largely a national-level parameter (producers will face similar wellhead prices across different regions), the REC costs and potential natural gas emissions may be highly variable across the country. Extrapolating what may be high or low end costs or potential natural gas emissions whose variation is driven by local or regional factors to a national-level estimate may overestimate or underestimate potential cost or emissions impacts. Second, this analysis holds the number of hydraulically fractured natural gas well completions constant regardless of economic conditions.

[18] "Statistical Analysis Memo: Development of a Bayesian Posterior Interval for the Emission Factor for Hydraulically Fractured Well Completions" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Annex to the Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

It is likely that the decision to perform a REC without a regulatory requirement is conditioned on the producer having already decided to drill and hydraulically fracture a natural gas well. If economic and technical conditions are conducive to drilling and hydraulically fracturing a natural gas well, it is also possible that conditions are such that RECs are more likely to be profitable if performed. Conversely, if gas prices were low, we would expect fewer completions, and hence fewer RECs. Consequently, the assumption of a fixed number of completions will tend to overstate total compliance cost estimates.

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 lines), as well as a function of the low, average, or high REC costs assumed faced by all producers nationally. 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.

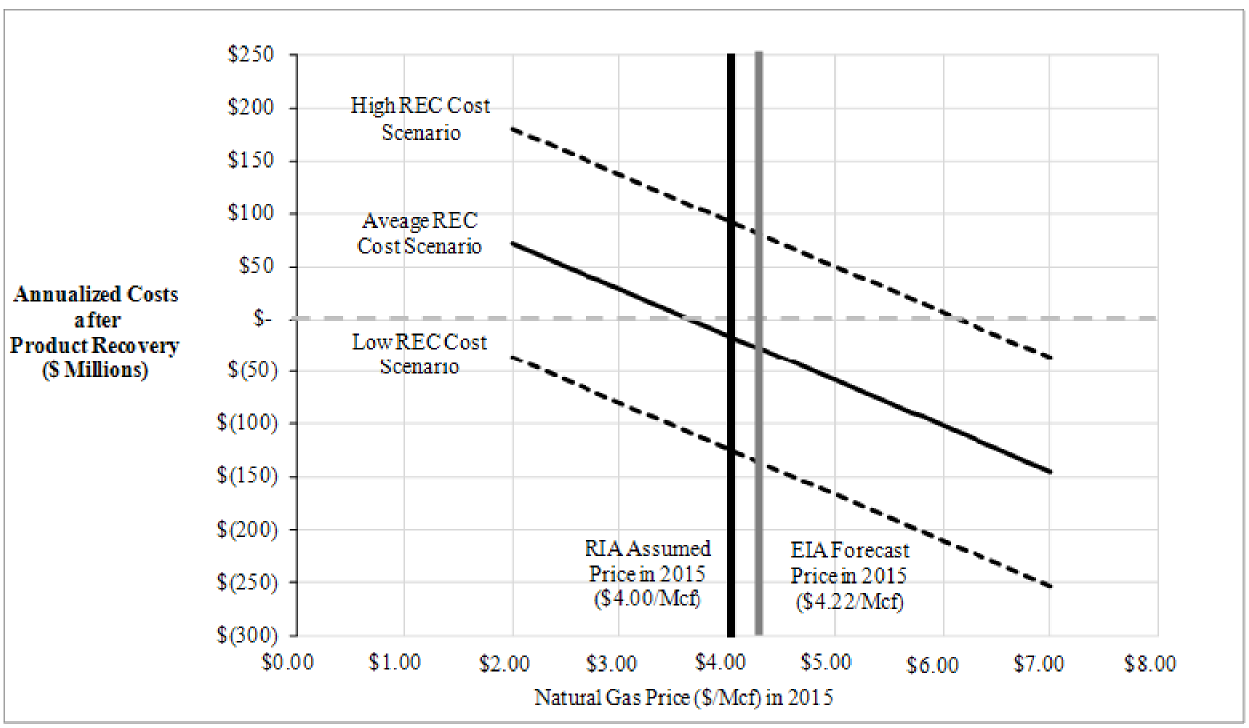

Figure 3-1 Sensitivity of Final NSPS Annualized Costs to Natural Gas Prices and REC Costs

As also shown in Table 3-6, at $4/Mcf and average REC costs, the annualized costs are estimated at -$15 million. At $4.22/Mcf, the price forecast reported in the 2011 Annual Energy Outlook, the annualized costs are estimated at about -$24 million. As indicated by this difference, EPA has chosen a relatively conservative assumption (leading to an estimate of lower savings and higher net costs) for the engineering costs analysis. The natural gas price at which the final NSPS breaks-even is around $3.66/Mcf. As mentioned earlier, a $1/Mcf change in the wellhead natural gas price leads to about a $43 million change in the annualized engineering costs of the final NSPS. Consequently, annualized engineering costs estimates would increase to about $29 million under a $3/Mcf price or decrease to about -$58 million under a $5/Mcf price.

Meanwhile, varying the REC costs shifts the line representing annualized costs downward in the low REC cost scenario and upward in the high REC cost scenario. At the $4/Mcf assumed wellhead natural gas prices, the annualized costs in the low REC cost scenario would be about -$120 million. At the $4/Mcf assumed wellhead natural gas prices, the annualized costs in the high REC cost scenario would be about $94 million.

Figure 3-2 similarly plots the annualized costs as function of the assumed price of natural gas paid to producers, but also depicts how the annualized costs might change when the potentials emissions might differ from our estimate of the national average well.

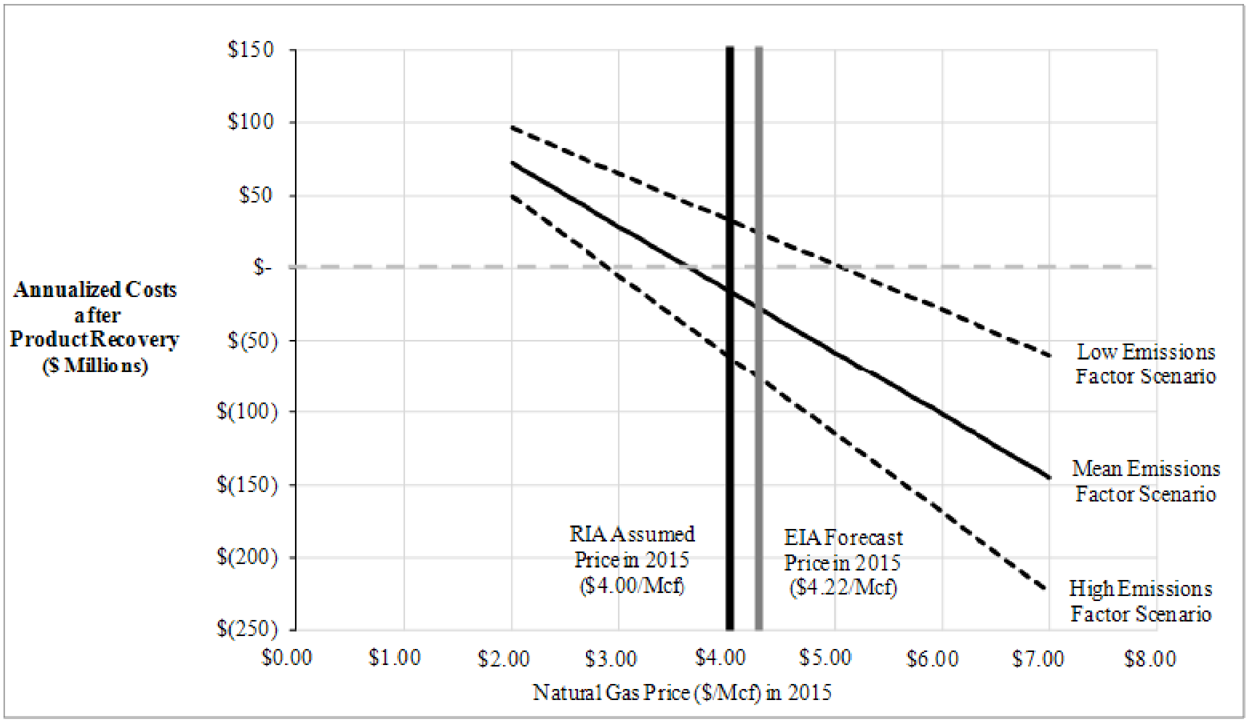

Figure 3-2 Sensitivity of Final NSPS Annualized Costs to Natural Gas Prices and Emissions Factor for Hydraulically Fractured Natural Gas Well Completions

As with the average REC costs, factor the annualized costs are estimated at -$15 million when using the average emissions. Varying the emissions factor shifts the line representing annualized costs upward in the low emissions factor scenario and downward in the high emissions factor cost scenario. At the $4/Mcf assumed wellhead natural gas prices, the annualized costs in the low emissions factor scenario would be about $33 million. At the $4/Mcf assumed wellhead natural gas prices, the annualized costs in the high emissions factor cost scenario would be about -$60 million.

The models used to forecast natural gas prices in the Annual Energy Outlook, also the source of our $4/Mcf wellhead natural gas price assumption, are deterministic. A deterministic model does not incorporate stochastic influences and produces the same result for each model run using the same inputs and parameters. While the Annual Energy Outlook is a commonly referenced publication that provides longer term forecasts, the U.S. EIA also produces the Short-Term Energy Outlook (STEO) which provides information about the probability distribution of energy prices over a shorter time frame. To better understand the uncertainty associated with the 2015 natural gas price assumed in this analysis, EPA reviewed the March 2012 STEO (U.S. EIA, 2012), which includes monthly forecasted natural gas prices through 2013. While the STEO analysis only extends to the end of 2013, the discussion of the distribution of possible future natural gas prices until that point can illuminate the uncertainty around longer-term forecasts.

In the STEO, forecasted prices are a function of the volatility associated with a future-delivery contract, as well as the length of time until contract expiration. The STEO also incorporates an analysis of the probabilities that natural gas prices would fall below or exceed specified prices through 2013. We note, however, that the probability analysis uses the Henry Hub spot price, rather than the wellhead price paid to producer. The Henry Hub price will reflect markups for processing and transportation unlike the wellhead price.[19] In December 2013, the EIA analysis projects a Henry Hub price of $4.28/million Btu (or $4.40/Mcf[20]) with a 90 percent confidence interval of $2.36 to $7.16/million Btu.

Also, the STEO reports that based upon futures prices as of February 2012, spot natural gas prices in December 2013 at the Henry Hub have a 40 percent probability of being greater than $4.00 per million Btu; a 30 percent probability of being greater than $4.50 per million Btu; a 20 percent probability of being greater than $5.00 per million Btu; and a 10 percent probability of being less than $2.50 per million Btu (U.S. EIA, 2012). While this information is not directly comparable to the wellhead natural gas price, the probability analysis highlights the challenges associated with precisely predicting future natural gas prices.

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 3-4 for these combustion-type controls, the final NSPS is

[19] The National Energy Modeling System used to produce the Annual Energy Outlook does not explicitly model prices at the Henry Hub. Rather, the model uses an econometric equation to predict Henry Hub prices from modeled wellhead prices. For the forecasts presented in 2012 Annual Energy Outlook, this equation predicts the Henry Hub price to be about 13 percent higher than the wellhead price.

[20] The 2015 natural gas price used in EPA's analysis is in units of thousand cubic feet and the spot natural gas prices used in the probability analysis are in units of million Btu. The conversion factor we used to convert the Btu measure to the cubic foot measure is 1 Mcf equals 1.027 million Btu. While EPA is able to convert the mean estimate of future natural gas prices, we are not able to convert the distribution around the mean without additional information that was used in the probability analysis.

estimated to capture about 43 billion cubic feet (bcf) of natural gas and 160,000 barrels of condensate. Estimates of unit-level and nation-level product recovery are presented in Table 3-7 below. Note that completion-related requirements for new and existing wells generate all the condensate recovery for the NSPS. For natural gas recovery, RECs contribute about 38 bcf (or 87 percent).

Table 3-7 Estimates of Control Unit-level and National-level Natural Gas and Condensate Recovery, Sources and Emissions Points, Primary Baseline, NSPS, 2015

		Unit-level Product Recovery		Total Product Recovery	
Source/ Emissions Points	**Projected No. of Affected Units**	**Natural Gas Savings (Mcf/unit)**	**Condensate (bbl/unit)**	**Natural Gas Savings (Mcf)**	**Condensate (bbl)**
Well Completions					
Hydraulically Fractured Gas Wells that Meet Criteria for REC	4,107	8,100	34	33,268,158	139,644
Hydraulically Refractured Gas Wells that Meet Criteria for REC	532	8,100	34	4,309,200	18,088
Equipment Leaks					
Processing Plants	29	950	0	27,548	0
Reciprocating Compressors					
Gathering and Boosting Stations	210	397	0	83,370	0
Processing Plants	209	1,079	0	225,540	0
Centrifugal Compressors					
Processing Plants	13	12,526	0	162,844	0
Pneumatic Controllers					
Oil and Gas Production	13,632	386	0	5,254,997	0
Processing Plants	15	871	0	13,064	0
Storage Vessels					
Emissions at least 6 tons per year	304	146	0	44,189	0
Total (Mcf)				**43,388,910**	**157,732**

A second adjustment to the natural gas quantities is necessary to account for nonhydrocarbon gases removed and gas that is 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 be consumed by final consumers.

After making these adjustments, we estimate that the final NSPS will potentially recover about 34 bcf of natural gas that will ultimately be consumed by natural gas consumers.[21] EIA forecasts that the domestic dry natural gas production in 2015 will be 22.4 tcf. Consequently, the final NSPS may recover production representing about 0.15 percent of domestic dry natural gas production predicted in 2015. 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 decision-making.

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, using the engineering compliance costs estimates, the estimates of natural gas product recovery, and assumed product prices (Table 3-8). The rates of return presented in Table 3-8 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 3-8 Simple Rate of Return Estimate for Final NSPS Controls, Primary Baseline

Emission Point	Control Option	Cost of Control	Revenues from Product Recovery	Estimated Rate of Return
New Completions of Hydraulically Fractured Wells	REC/ Combustion	$33,237	$34,780	4.6%
Reciprocating Compressors (Processing Plants)	Replace packing	$2,090	$4,317	106.5%
Centrifugal Compressors (Processing Plants)	Route to control	$3,132	$50,106	1499.7%
Pneumatic Controllers (Oil and Gas Production)	Emissions limit	$23	$1,542	6467.3%
Overall NSPS*		**$169,914,312***	**$184,596,889***	**8.6%***

* Costs and estimated rate of return for overall NSPS based on national costs of rule, not per unit costs like the other items in the table.
Note: The table presents only control options where estimated revenues from natural gas product recovery exceeds estimated annualized engineering costs

[21] 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.

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 vary 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 4.6 percent rate estimated for a REC, 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 RIA nevertheless is based on the observation that emission reductions that appear to be profitable, on average, in our analysis have not been adopted by a significant segment of the industry. This observation, often termed the "energy paradox", has been noted to occur in other contexts too where consumers and firms appear to undervalue a wide range of investments in energy conservation, even when they pay off over relatively short time periods.[22] We discuss some possible explanations for the apparent paradox in this context. First, there may be an opportunity cost associated with the installation of environmental controls (for purposes of mitigating the emission of pollutants) that is not reflected in the control costs. In the event that the environmental investment displaces other investment in productive capital, the difference between the rate of return on the marginal investment displaced by the mandatory environmental investment is a measure of the opportunity cost of the environmental requirement to the regulated entity. However, if firms are not capital constrained, then there may not be any displacement of investment, and the rate of return on other investments in the industry would not be relevant as a measure of opportunity cost. If firms should face higher borrowing costs as they take on more debt, there may be an additional opportunity cost to the firm. To the extent that any opportunity costs are not added to the control costs, the compliance costs presented above may be underestimated.

A second explanation could be that the average impacts identified in this RIA are not reflective of the true costs and benefits of the RECs that are compelled by the regulation, relative

[22] See U.S. EPA (2011) for more discussion and a review of the economics literature examining why firms may not adopt technologies that would be expected to increase their profits. (U.S. EPA. 2011. Final Rulemaking to Establish Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles. Regulatory Impact Analysis. http://www.epa.gov/otaq/climate/documents/420r11901.pdf).

to the RECs performed voluntarily. In this final rule, based on public comments and explained above, EPA has identified several circumstances under which RECs would not be feasible or cost-effective, and has allowed firms to continue to use combustion devices only for those completions and recompletions. In addition to these general categories, the natural variation in well-head prices, cost, or other technical issues may mean that the rational decision to not complete using a REC in the absence of this regulation in certain circumstances may not be captured by the analysis of central estimate impacts contained in this RIA. In part to address this issue, EPA has provided the break-even analysis above, as well as a sensitivity analysis where we vary several parameters that may influence individual REC decision-making.

Third, the assumed $4/Mcf payment rate does not reflect any taxes or royalties that might apply to producers implementing the control technologies. We expect that royalties and taxes influence producers' economic and operational decisions, particularly at the margin, as these royalties or taxes reduce potential net returns and prevent adoption of environmental controls. However, there are various reductions in taxable income and incentives that can serve to reduce costs which also can affect decisionmaking. For example, firms may be able to deduct pollution control expenditures and depreciation from income taxes. Also, for the oil and natural gas industry, producers may be eligible for deductions of intangible drilling costs and other state or federal production and investment credits. Historically, EPA has not estimated post-tax (or post-royalty) compliance costs (which are typically cost-reducing) in compliance cost estimation as this requires information and tax accounting beyond the scope of the analyses.

A third 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 a significant percent of new natural gas well completions with hydraulic fracturing and existing natural gas well recompletions with hydraulic fracturing are estimated to be controlled in the baseline, it is unlikely that a lack of information will be a major 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.

Finally, the cost from the 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 engineering compliance costs presented in Table 3-2 and Table 3-4 using the additional product recovery and associated revenues. EPA continues to explore what factors could explain apparent underinvestment in cost-effective emission reducing technologies absent government regulation, and the measurement of opportunity costs more generally.

3.2.2.2 NESHAP Sources

As discussed in Section 3.2.1.2, EPA examined two emissions points as part of its analysis for the final NESHAP Amendments. Unlike the controls for the final NSPS, the controls evaluated under the final NESHAP Amendments do not direct significant quantities of natural gas that would otherwise be flared or vented into the production stream. Table 3-9 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 HAP, VOC, and methane, as well as a cost-effectiveness estimate for HAP reduction, based upon annualized engineering costs.

Table 3-9 Summary of Estimated Capital and Annual Costs, Emissions Reductions, and HAP Reduction Cost-Effectiveness for Final NESHAP Amendments

Source/Emissions Point	Projected No. of Controls Required	Capital Costs/ Unit (2008$)	Annual-ized Cost/Unit (2008$)	Total Annualized Cost (2008$)	Emission Reductions (tons per year) HAP	VOC	Methane	HAP Reduction Cost-Effectiveness (2008$/ton)
Production - Small Glycol Dehydrators	74	35,518	22,396	1,657,300	505	915	316	3,284
Transmission - Small Glycol Dehydrators	7	19,399	18,957	132,700	164	298	103	808
Reporting and Recordkeeping	N/A	N/A	N/A	1,694,907	N/A	N/A	N/A	N/A
Total	**81**			**3,484,907**	**669**	**1,213**	**419**	**5,209**

Note: Totals may not sum due to independent rounding.

Under the final NESHAP Amendments, about 81 controls will be required, costing a total of $3.5 million annually (Table 3-9). We include reporting and recordkeeping costs as a unique line item showing these costs for the entire set of final amendments. These controls will reduce HAP emissions by about 670 tons, VOC emissions by about 1,200 tons, and methane by about 420 tons. The cost-per-ton to reduce HAP emissions is estimated at about $5,200 per ton. All figures are in 2008 dollars.

3.3 References

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U.S. Energy Information Administration (U.S. EIA). 2012. Short-Term Energy Outlook March 2012. < http://205.254.135.7/forecasts/steo/uncertainty/index.cfm> March 6, 2012.

4 BENEFITS OF EMISSIONS REDUCTIONS

4.1 Introduction

The final 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 HAP, 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, as explained below. For the final NSPS, the HAP and climate benefits can be considered "co-benefits", and for the final 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 HAP and methane.

The final NSPS is anticipated to prevent, 190,000 tons of VOC, 11,000 tons of HAP, and 1.0 million tons of methane from new sources, while the final NESHAP Amendments are anticipated to reduce 670 tons of HAP, 1,200 tons of VOC, and 420 tons of methane from existing sources. The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits, including an increase of 1.1 million tons of carbon dioxide (CO_2), 550 tons of nitrogen oxides (NOx), 19 tons of PM, 3,000 tons of CO, and 1,100 tons of total hydrocarbons (THC). The specific control technologies for the NESHAP Amendments are anticipated to have minor secondary disbenefits, but EPA was unable to estimate these secondary disbenefits. Both rules would have additional emission changes associated with the energy system impacts. The net CO_2-equivalent emission reductions are 18 million metric tons for the final NSPS and 8,000 metric tons for the final 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.[23] 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 Section 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 VOC and HAP 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.[24]

[23] Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the 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). 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 between VOC emissions and $PM_{2.5}$ and the highly localized nature of air quality responses associated with VOC reductions, 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.

[24] 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.

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, 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 implementation rules are generally from a specific class of well-characterized sources. In general, EPA is more confident in the magnitude and location of the emission reductions for implementation rules rather than illustrative NAAQS analyses. 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. 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 the Oil and Natural Gas NSPS and NESHAP Amendments in 2015 (short tons per year)

Pollutant	NESHAP Amendments	NSPS
Primary Baseline		
HAP	669	11,487
VOC	1,213	188,741
Methane	419	1,010,382
Alternative Regulatory Baseline		
HAP	669	19,028
VOC	1,213	292,532
Methane	419	1,721,763

4.3 Secondary Impacts Analysis for Oil and Gas Rules

The control techniques to avert leaks and vents of VOC and HAP 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.[25] For example, by combusting VOC and HAP, 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.

[25] In previous RIAs, we have also referred to these impacts as energy disbenefits.

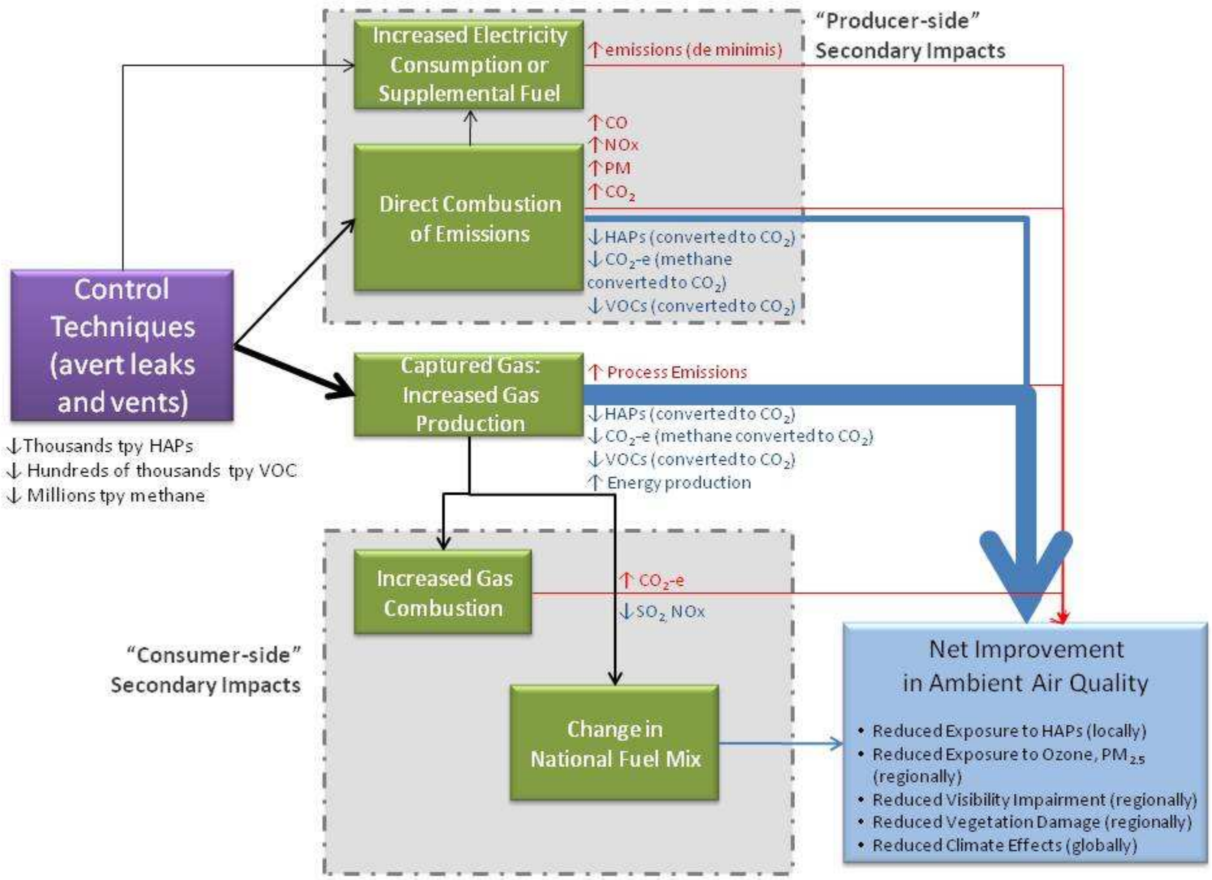

Figure 4-1 Conceptual Diagram of Secondary Impacts from Oil and Gas NSPS and NESHAP Amendments

Table 4-2 shows the estimated secondary "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).[26]

Table 4-2 Secondary Air Pollutant Impacts Associated with Control Techniques by Emissions Category, Primary Baseline ("Producer-Side") (short tons per year)

Emissions Category	**CO_2**	**NOx**	**PM**	**CO**	**THC**
Total Completions of New Gas Wells (NSPS)	981,559	504	15	2,745	1,039
New Gas Well Completions: REC/Combust	*133,177*	*68*	*0*	*372*	*141*
New Gas Well Completions: Combust	*848,382*	*436*	*15*	*2,373*	*898*
Existing Well Recompletions: Combust	91,800	47	1	257	97
Existing Well Completions: REC/Combust	*17,251*	*9*	*0*	*48*	*18*
Existing Well Completions: Combust	*74,549*	*38*	*1*	*208*	*79*
Pneumatic Controllers (NSPS)	22.0	1.0	2.6	0.0	0.0
Storage Vessels (NSPS)	856.0	0.5	0.0	2.4	0.9
Total NSPS	**1,074,237**	**553**	**19**	**3,004**	**1,137**

For the "consumer-side" impacts associated with the NSPS, we modeled the impact of the final NSPS on the national fuel mix and associated CO_2-equivalent emissions (Table 4-3).[27] We provide the modeled results of the "consumer-side" CO_2-equivalent emissions in Table 7-12.

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 0.65 million metric tons for the final NSPS and NESHAP Amendments in 2015. This is in addition to the other secondary impacts and directly avoided emissions, for a total 17.7 million metric tons of CO_2-equivalent emissions averted as shown in Table 4-4. While the NEMS is designed to estimate changes in fuel consumption as economic and regulatory factors change (such as are shown in Table 7-11), the NEMS is unable to estimate national-level emissions of criteria pollutants.

[26] This issue is discussed in more detail in Section 4.7 of this RIA.
[27] 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 Final Oil and Gas NSPS and NESHAP Amendments in 2015 (million metric tonnes) ("Consumer-Side")[1]

Fuel Type	NSPS (million metric tons change in CO_2-e)
Petroleum	-0.07
Natural Gas	0.04
Coal	0.68
Other	0.00
Total modeled Change in CO_2-e Emissions	**0.65**

[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 Final Oil and Gas NSPS and NESHAP Amendments in 2015 (million metric tonnes)

Emissions Source	**NSPS**	**NESHAP Amendments**
Averted CO_2-e Emissions from New Sources[1]	-19.2	-0.008
Additional CO_2-e Emissions from Combustion and Supplemental Energy (Producer-side)[2]	0.97	N/A
Total Modeled Change in Energy-related CO_2-e Emissions (Consumer-side)[3]	0.65	N/A
Total Change in CO_2-e Emissions after Adjustment for Secondary Impacts	**-17.6**	**-0.008**

[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.

[3] This estimate reflects the modeled change in the energy–related consumer-side impacts shown in Table 4-3 and reflects both NSPS and NESHAP Amendments.

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 rule.

Table 4-5 Summary of Emissions Changes for the Final Oil and Gas NSPS and NESHAP Amendments in 2015 (short tons per year)

	Pollutant	NSPS	NESHAP Amendments
Change in Direct Emissions	VOC	-190,000	-670
	Methane	-1,000,000	-1,200
	HAP	-11,000	-420
Change in Secondary Emissions (Producer-Side)	CO_2	1,100,000	N/A
	NOx	550	N/A
	PM	19	N/A
	CO	3,000	N/A
	THC	1,100	N/A
Change in Secondary Emissions (Consumer-Side)	CO_2-e	720,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e (short tons)	-19,000,000	-8,800
	CO_2-e (metric tonnes)	-18,000,000	-8,000

Note: 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).[28] The levels of air toxics to which people are exposed vary depending on where they 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.[29] The most recent NATA was conducted for calendar year 2005 and was released in March 2011. NATA includes four steps:

[28] The 2005 NATA is available on the Internet at http://www.epa.gov/ttn/atw/nata2005/.

[29] 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.[30,31] 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,[32] subchronic,[33] or acute[34] 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.

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[30] 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.

[31] 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.

[32] Chronic exposure is defined in the glossary of the Integrated Risk Information System (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).

[33] 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).

[34] 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.[35] Thus, it is important to account for the toxicity and exposure, as well as the mass of the targeted emissions.

[35] 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.

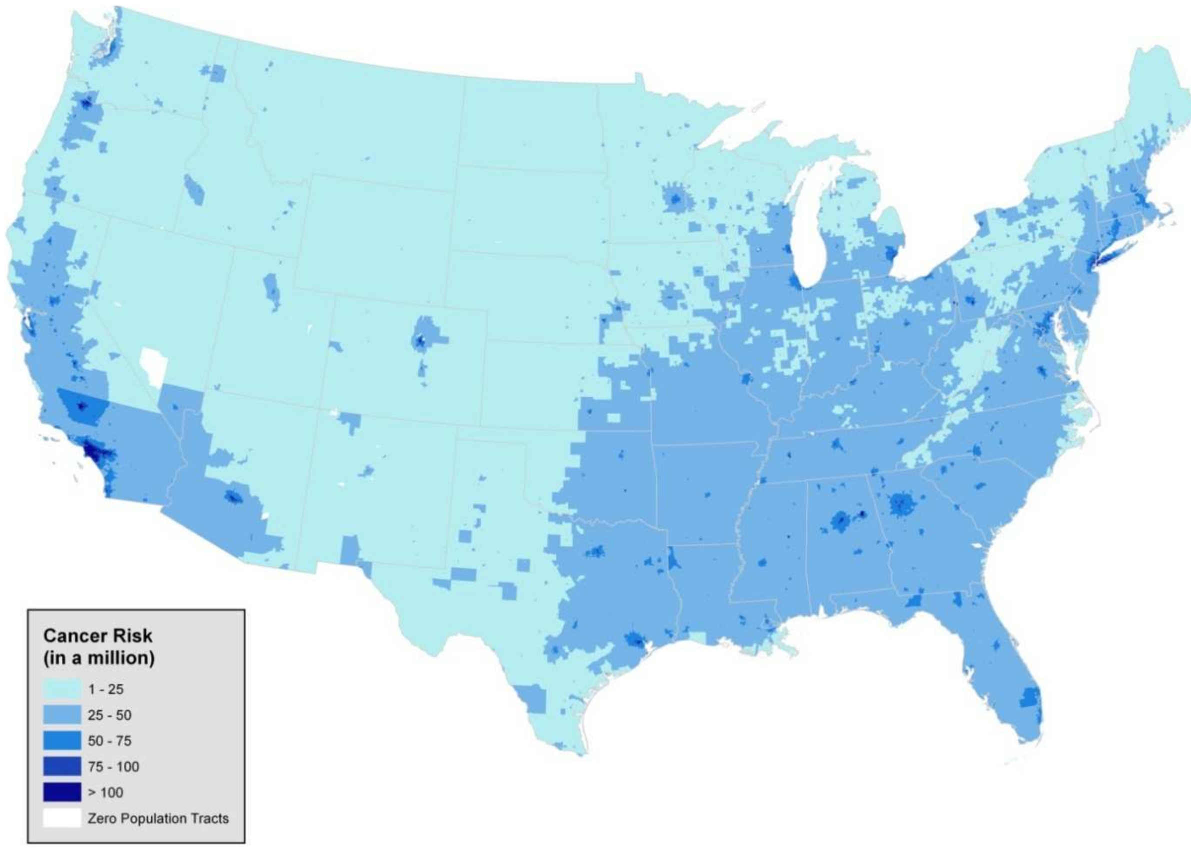

Figure 4-2 Estimated Chronic Census Tract Carcinogenic Risk from HAP exposure from outdoor sources (2005 NATA)

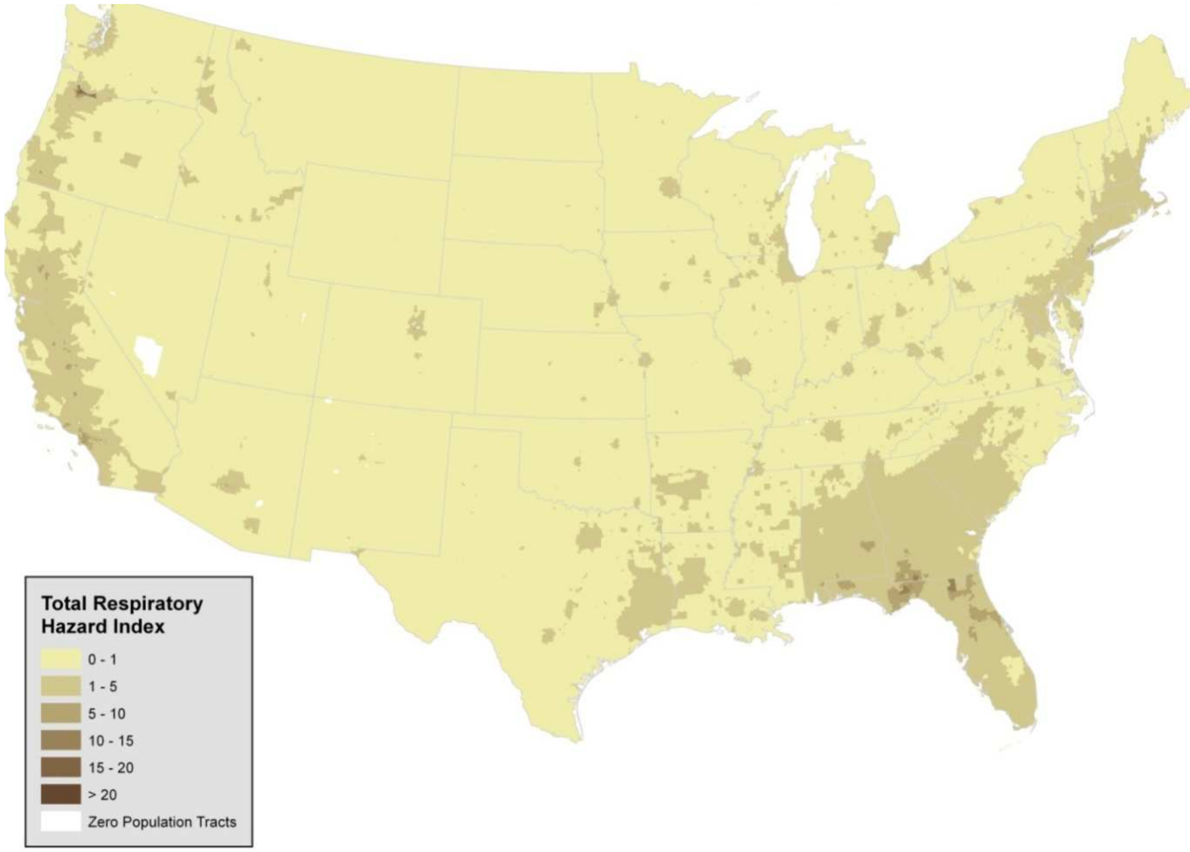

Figure 4-3 Estimated Chronic Census Tract Noncancer (Respiratory) Risk from HAP exposure from outdoor sources (2005 NATA)

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 HAP, EPA has quantified the benefits of potential reductions in the incidences of cancer and noncancer risk (e.g., U.S. EPA, 1995). In those analyses, EPA relied on unit risk factors (URF) developed through risk assessment procedures.[36] 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

[36]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 µg/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 HAP.

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 (HAP) 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 HAP. 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 HAP, 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 HAP in this analysis. Instead, we provide a qualitative analysis of the health effects associated with the HAP 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 HAP are emitted from oil and natural gas operations, either from equipment leaks, processing, compressing, transmission and distribution, or storage tanks. Emissions of eight HAP make up a large percentage of 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 HAP 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 20,000 tons of HAP 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, 2012). The results for oil and gas production indicate that maximum lifetime individual cancer risks could be 10 in-a-million for existing sources with a cancer incidence of 0.02 before and after controls. Approximately 120,000 people are estimated to have cancer risks at or above 1-in-1 million for oil and gas production. For existing natural gas transmission and storage, the maximum individual cancer risk could be 20-in-a-million with a cancer incidence of 0.001. Approximately 1,100 people are estimated to have cancer risks at or above 1-in-1 million for oil and gas transmission and storage. Benzene is the primary cancer risk driver. The results also indicate that significant noncancer impacts from existing sources are unlikely, especially after controls. It is important to note that the magnitude of the HAP emissions avoided by new sources with the NSPS are much 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.[37,38,39] EPA states in its IRIS database that data indicate a causal

[37] 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.

[38] 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.

[39] 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.[40,41] 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.[42,43] The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[44,45] 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.[46,47,48,49] EPA's IRIS program has not yet evaluated these new data.

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[40] 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.

[41] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: http://ntp.niehs.nih.gov/go/16183.

[42] Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. Environ. Health Perspect. 82: 193-197.

[43] Goldstein, B.D. (1988). Benzene toxicity. Occupational medicine. State of the Art Reviews. 3: 541-554.

[44] 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.

[45] 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.

[46] 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.

[47] 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.

[48] Lan, Qing, Zhang, L., Li, G., Vermeulen, R., et al. (2004). Hematotoxically in Workers Exposed to Low Levels of Benzene. Science 306: 1774-1776.

[49] 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[50]

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

[50] 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.[51] 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.[52]

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.[53,54] 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).[55,56] The NTP (1999) carried out a chronic inhalation

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[51] 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.

[52] 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.

[53] 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.

[54] 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.

[55] 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.[57] Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys.[58] 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.[59] 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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[56] 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.

[57] 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.

[58] 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.

[59] 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.[60]

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.[61]

4.5 VOC

4.5.1 VOC as a $PM_{2.5}$ precursor

This rulemaking would reduce emissions of VOC, which are a precursor to $PM_{2.5.}$ Most VOC 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

[60] 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>.

[61] 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 and data limitations regarding locations of new well completions, 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 VOC 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 (2011g)). 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 the 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 VOC, 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.[62] 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

[62] 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.

emissions across all sectors. Coupled with the larger uncertainties about the relationship 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 VOC (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, 2011g; 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 VOC as an Ozone Precursor

This rulemaking would reduce emissions of VOC, 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 VOC and CO are important compounds for ozone formation, but biogenic VOC 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 VOC. 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 VOC. Between these areas, ozone is relatively insensitive to marginal changes in both NOx and VOC.

Due to time limitations under the court-ordered schedule and data limitations, 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 and data limitations regarding the location of new well completions, we are unable to estimate the effect that reducing VOC 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 VOC from industrial boilers resulted in $3.6 to $15 million of monetized benefits from reduced ozone exposure (U.S. EPA, 2011b).[63] This implies a benefit-per-ton for ozone reductions of $240 to $1,000 per ton of VOC 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

[63] 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.

consistent with emissions modeled in the boiler analysis. Therefore, we do not believe that those 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.

4.7 Methane (CH_4)

4.7.1 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 that contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone also impacts global temperatures. 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.

According to the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (2007), changes in methane concentrations since 1750 contributed 0.48 W/m^2 of forcing, which is about 18% of all global forcing due to increases in anthropogenic GHG concentrations, and which makes methane the second leading long-lived climate forcer after CO_2. However, after accounting for changes in other greenhouse substances such as ozone and stratospheric water vapor due to chemical reactions of methane in the atmosphere, historical methane emissions were estimated to have contributed to 0.86 W/m^2 of forcing today, which is about 30% of the forcing due to historical greenhouse gas emissions.

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 final rule 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 finalizes emission control technologies and regulatory alternatives that will significantly decrease methane emissions from the oil and natural gas sector in the United States. The NSPS is expected to reduce methane emissions annually by about 1.0 million short tons or approximately 19 million metric tons CO_2-e. These reductions represent about 7 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 18 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 4 million typical passenger cars off the road or eliminating electricity use from about 2 million typical homes each year.[64]

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

[64] US Environmental Protection Agency. Greenhouse Gas Equivalency Calculator available at: http://www.epa.gov/cleanenergy/energy-resources/calculator.html accessed 02/13/12.

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.[65] 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.

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.

[65] The interagency group concluded that a global measure of the benefits from reducing U.S. emissions is preferable. The development of a domestic SCC is greatly complicated by the relatively few region- or country-specific estimates of SCC in the literature. See Interagency Working Group on Social Cost of Carbon. 2010. Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.

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 relatively 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 longer-lived gases such as CO_2, 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.

The EPA recognizes that the methane reductions finalized in this rule will provide significant economic climate co-benefits to society. However, the 2009-2010 Interagency Social Cost of Carbon Work Group did not produce directly modeled estimates of the social cost of methane. In the absence of direct model estimates from the interagency analysis, EPA has used a "global warming potential (GWP) approach" to estimate the dollar value of this rule's methane co-benefits. Specifically, EPA of converted methane to CO_2 equivalents using the GWP of methane, then multiplied these CO_2-equivalent emission reductions by the social cost of carbon developed by the Interagency Social Cost of Carbon Work Group.

EPA requested 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. EPA's response to these comments, as well as a summary of the public comments sent in response to this request, is provided in the response to comments document.

Applying the GWP approach, these co-benefits equate to a range of approximately $130 to $1,600 per metric ton of methane reduced depending upon the discount rate assumed, with an estimate of $840 per ton using the mean SCC at the 3 percent discount rate.[66] When including expected methane emission reductions from the NESHAP Amendments and NSPS and considering secondary impacts of the oil and gas rule, the 2015 co-benefits vary by discount rate and range from about $100 million to about $1.3 billion; the mean SCC at the 3 percent discount rate ($25 per metric ton) results in an estimate of $440 million in 2015 (Table 4-7).

[66] The per ton estimates range from approximately $110 to $1400 per short ton of methane reduced, depending on the discount rate assumed, with an estimate of $480 per short ton of methane, using the mean SCC at 3% discount rate.

Table 4-7 Climate Methane Benefits Using 'GWP' Approach

SCC Value for 2015 emission reductions ($/ton CO_2 in 2008 dollars) [1]	Total Benefits based on 100 year GWP adjustment[2] (millions 2008$)	
	Final NSPS	**Final NESHAP Amendments**
$6 (mean 5% discount rate)	$100	$0.05
$25 (mean 3% discount rate)	$440	$0.20
$40 (mean 2.5% discount rate)	$700	$0.32
$76 (95th percentile at 3% discount rate)	$1,300	$0.60
Methane Emission Reductions [3] (MMT CO_2-e)	**17.6**	**0.008**

[1] SCC values for 2015 from the SCC TSD in the light duty vehicle rule adjusted to reflect 2008$ using the CPI-U from the Bureau of Labor Statistics.
[2] Estimates are given for illustrative purposes and represent the CO_2-e estimate of methane reductions multiplied by the SCC estimates ("GWP approach").CO_2-e calculated using the GWP of 21 (SAR). These co-benefit estimates are not the same as would be derived using a social cost of methane directly computed from integrated assessment models. See Marten and Newbold (2011) for discussion of the limitations of the GWP approach.
[3] Estimates include methane reductions from the NSPS and NESHAP Amendments respectively and consider secondary impacts from Table 4-4.
Note: Results reflect independent rounding.

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 (details below). 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 rule. The use of the SAR GWP values allows comparability of data collected in this final 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 finalized in this rulemaking.

Given the uncertainties with both the ‘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 final rule. Rather, the EPA presents the ‘GWP approach’ climate co-benefit estimates as an interim method to produce estimates until the interagency group develops values for non-CO_2 GHGs.

4.7.2 Methane as an ozone precursor

This rulemaking would reduce emissions of methane, a GHG and also a precursor to ozone. In remote areas, methane is a dominant precursor to tropospheric ozone formation (U.S. EPA, 2006a). Approximately 40% of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane (HTAP, 2010). Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future (HTAP, 2010). Unlike NOx and VOC, which affect ozone concentrations regionally and at hourly time scales, methane emissions affect ozone concentrations globally and on decadal time scales given methane's relatively long atmospheric lifetime (HTAP, 2010). Reducing methane emissions, therefore, can reduce global background ozone concentrations, human exposure to ozone, and the incidence of ozone-related health effects (West et al., 2006, Anenberg et al., 2009). These benefits are global and occur in both urban and rural areas. Reductions in background ozone concentrations can also have benefits for agriculture and ecosystems (UNEP/WMO, 2011). Studies show that controlling methane emissions can reduce global ozone concentrations and climate change simultaneously, but controlling other shorter-lived ozone precursors such as NOx, carbon monoxide, or non-methane VOC may have larger local health benefits from greater reductions in ozone concentrations (West and Fiore, 2005; West et al., 2006, 2007; Fiore et al. 2008; Dentener et al., 2005; Shindell et al., 2005, 2012; UNEP/WMO, 2011).VOC 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.

4.7.3 Combined methane and ozone effects

A recent United Nations Environment Programme (UNEP) assessment provides the most comprehensive analysis to date of the health, climate, and agricultural benefits of measures to reduce methane, as well as black carbon, a component of fine particulate matter that absorbs radiation (UNEP/WMO, 2011; Shindell et al., 2012). The UNEP assessment found that while reducing longer-lived GHGs such as CO_2 is necessary to protect against long-term climate change, reducing global methane and black carbon emissions would have global health benefits by reducing exposure to ozone and $PM_{2.5}$ as well as potentially slowing the rate of climate change within the first half of this century. Relative to a business as usual reference scenario, implementing methane mitigation measures that achieve approximately 40% reductions in global methane emissions were estimated to avoid approximately 0.3° C globally averaged warming in 2050 (including the impacts of both methane itself and subsequently formed ozone) and 47,000 ozone-related premature deaths and 27 million metric tons of ozone-related crop yield losses globally in 2030 (Shindell et al., 2012). These benefits, including global climate impacts of methane and resulting ozone changes, and global ozone-related health and agricultural impacts, were valued at $700 to $5,000 per metric ton[67]. The methane measures examined include extended methane recovery/utilization and reduced fugitive emissions from oil and gas production, which contributed the greatest climate benefit of all methane mitigation measures in North America and Europe (UNEP, 2011).

4.8 References

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[67] Benefit per ton values derived from Shindell et al. (2012) cannot be directly compared to, nor are they additive with, the ozone health benefit-per-ton estimates for the U.S. reported in Section 4.6.1, since they include climate and agricultural impacts, are calculated for global rather than U.S. impacts, and use different assumptions for the value of a statistical life. Similarly, these values cannot be compared to, nor are they additive with, the methane climate valuation estimates in Section 4.7.1 since they include health and agricultural benefits and use different assumptions for the Social Cost of Carbon.

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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 section 3(f)(1) 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 the Office of Management and Budget (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. Table 5-1 shows the results of the cost and benefits analysis for these final rules.

Table 5-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Final Oil and Natural Gas NSPS and NESHAP Amendments in 2015[1]

	NSPS	**NESHAP Amendments**	**NSPS and NESHAP Amendments Combined**
Total Monetized Benefits[2]	N/A	N/A	N/A
Total Costs[3]	-$15 million	$3.5 million	-$11 million
Net Benefits	N/A	N/A	N/A
Non-monetized Benefits[6]	11,000 tons of HAP	670 tons of HAP	12,000 tons of HAP
	190,000 tons of VOC	1,200 tons of VOC	190,000 tons of VOC
	1.0 million tons of methane	420 tons of methane	1.0 million tons of methane
	Health effects of HAP exposure[5]	Health effects of HAP exposure	Health effects of HAP exposure
	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 product 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 HAP, 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.

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the final 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] For the NSPS, reduced exposure to HAP and climate effects are co-benefits. For the NESHAP, reduced VOC emissions, $PM_{2.5}$ and ozone exposure, visibility and vegetation effects and climate effects are co-benefits.

[6] The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits, including an increase of 1.1 million tons of carbon dioxide (CO_2), 550 tons of nitrogen oxides NOx, 19 tons of PM, 3,000 tons of CO, and 1,100 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The specific control technologies for the NESHAP are anticipated to have minor secondary disbenefits but EPA was unable to estimate these secondary disbenefits. The net CO_2-equivalent emission reductions are 18 million metric tons.

5.2 Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C.

3501, et seq. The information collection requirements are not enforceable until OMB approves them.

The ICR documents prepared by the EPA have been assigned EPA ICR numbers 2437.01, 2438.01, 2439.01 and 2440.01. The information requirements 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 CAA section 114 (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. This final rule requires 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.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of 40 CFR part 63, subpart HH or 40 CFR part 63, subpart HHH. An affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonable preventable, and not caused by poor maintenance and or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense.

For this rule, the EPA is adding affirmative defense to the estimate of burden in the ICR. To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, the EPA has provided administrative adjustments to this ICR that shows what the notification, recordkeeping and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA's estimate for the required notification, reports, and records, including the root cause analysis, associated with a single incident totals approximately totals $3,141 and is based on the time and effort required of a source to review relevant data, interview plant employees, and document the events surrounding a malfunction that has caused an exceedance of an emission limit. The estimate also includes time to produce and retain the record and reports for submission to the EPA. The EPA provides this illustrative estimate of this burden, because these costs are only incurred if there has been a violation, and a source chooses to take advantage of the affirmative defense.

The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense. Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of excess emissions caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we believe the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small.

For this reason, we estimate a total of 39 such occurrences for all sources subject to 40 CFR part 63, subpart HH, a total of three such occurrences for all sources subject to 40 CFR part 63, subpart HHH, and a total of 6 such occurrences for all sources subject to 40 CFR part 60, subparts KKK and LLL over the 3-year period covered by this ICR. We expect to gather information on such events in the future, and will revise this estimate as better information becomes available.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $20.1 million. This includes 384,866 labor hours per year at a total labor cost of $19.5 million per year, and annualized capital costs of $0.36 million, and annual operating and maintenance costs of $0.20 million. This estimate includes initial and annual performance tests, semiannual excess emission reports, developing a monitoring plan, notifications, and recordkeeping. All burden estimates are in 2008 dollars and represent the most cost effective monitoring approach for affected facilities. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When these ICR are approved by OMB, the agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control numbers for the approved information collection requirements contained in the final rule.

5.3 Regulatory Flexibility Act

The Regulatory Flexibility Act 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 (SISNOSE). Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impact of this rule on small entities, a small entity is defined as: (1) A small business as defined by NAICS codes 211111, 211112, 221210, 486110 and 486210; 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.

For the final NSPS, the EPA performed an analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. The baseline used in this analysis takes into account RECs conducted pursuant to state regulations covering these operations and estimates of RECs performed voluntarily. To account for RECs performed in regulated states, EPA subsumed emissions reductions and compliance costs in states where these completion-related emissions are already controlled into the baseline. Additionally, based on public comments and reports to EPA's Natural Gas STAR program, EPA recognizes that some producers conduct well completions using REC techniques voluntarily for economic and/or environmental objectives as a normal part of business. To account for emissions reductions and costs arising from voluntary implementation of pollution controls EPA used information on total emission reductions reported to the EPA by partners of the EPA Natural Gas STAR. This estimate of this voluntary REC activity in the absence of regulation is also included in the baseline. More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket.

When revenue from additional natural gas product recovered is not included, we estimate that 123 of the 127 small firms analyzed (97 percent) are likely to have impacts less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, four firms (3 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. However, when revenue from additional natural gas product recovery is included, we estimate that none of the analyzed firms will have an impact greater than 1 percent.

For the final NESHAP Amendments, we estimate that 11 of the 35 firms (31 percent) that own potentially affected facilities are small entities. The EPA performed an analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, none are likely to have impacts greater than 1 percent in terms of the ratio of annualized compliance costs to revenues.

After considering the economic impact of the combined NSPS and NESHAP amendments on small entities, I certify this action will not have a significant impact on a substantial number of small entities (SISNOSE). While both the NSPS and NESHAP amendment would individually result in a no SISNOSE finding, the EPA performed an additional analysis in order to certify the rule in its entirety. This analysis compared compliance costs to entity revenues for the total of all the entities affected by the NESHAP amendments and the sample of entities analyzed for the NSPS. When revenues from additional natural gas product sales are not included, 132 of the 136 small firms (97 percent) in the sample are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, four firms (3 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. When revenues from additional natural gas product sales are included, none of the 136 small firms (100 percent) are likely to have impacts of greater than 1 percent.

Our 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 REC 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 occur over a short span of time, during which the additional product recovery is also accomplished and payments for recovered products are settled.

Although this final rule will not impact a substantial number of small entities, the 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 final action does not contain a federal mandate under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531-1538 for state, local, and tribal governments, in the aggregate, or to the private sector. The action would not result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any 1 year. Thus, this final rule is not subject to the requirements of sections 202 or 205 of UMRA.

This final 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 action 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. These final rules primarily affect private industry, and do not impose significant economic costs on state or local governments. Thus, Executive Order 13132 does not apply to this action.

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 action will not have tribal implications because it doesn't impose a significant cost to the tribal government. However, there are significant tribal interests because of the growth of the oil and gas production industry in Indian country.

The EPA initiated a consultation process with tribal officials early in the process of developing this regulation to permit them to have meaningful and timely input into its development. During the consultation process, the EPA conducted outreach and information meetings prior to the proposal in 2010. The EPA met with the Inter Tribal Environmental Council, which include many of the Region VI tribes, The Tribal leadership summit in Region X, and Tribal Energy Conference hosted by Ft. Belknap, and the National Tribal Forum.

After the proposal was published, letters were sent to all tribal leaders offering to consult on a government-to-government basis on the rule. As part of the consultation process and in response to these letters, an outreach call was held on October 12, 2011. Tribes that participated on this call were: Fond du Lac Band of Lake Superior Chippewa, Fort Belknap Indian

Community, Forest County Potawatomi Community, Southern Ute Indian Tribe, and Pueblo of Santa Clara.

In this meeting the tribes were presented the information in the proposal. The tribes asked general clarifying questions but did not provide specific comments. Comments on the proposal were received from an affiliate of the Southern Ute Indian Tribe. The commenter expressed concern about the impacts of the rule on natural gas and oil production operations on the Southern Ute Indian reservation and requested additional time to evaluate the impacts. In response to this and other requests, the comment period was extended. More specific comments can be found in the docket.

5.7 Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because the Agency does not believe the environmental health risks 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. The EPA's risk assessments (included in the docket for this final 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

This action is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. These final 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 final NESHAP amendments are unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the final NESHAP amendments are not "significant energy actions" as defined in Executive Order 13211, (66 FR 28355, May 22, 2001). The final NSPS is also unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the final NSPS is not a “significant energy action” as defined in Executive Order 13211 (66 FR 28355, May 22, 2001).

The basis for these determinations is as follows. 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 final NSPS also captures saleable condensates. The revenues from additional natural gas and condensate recovery are expected to offset the costs of implementing the final rules.

We use the National Energy Modeling System (NEMS) to estimate the impacts of the combined final rules 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 DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

Based on public comments and reports to EPA's Natural Gas STAR program, EPA recognizes that some producers conduct well completions using REC techniques, which are required by the final NSPS for certain completions of hydraulically fractured and refractured natural gas wells, voluntarily based upon economic and environmental objectives. The baseline used for the energy system impacts analysis takes into account RECs conducted pursuant to state regulations covering these operations and estimates of RECs performed voluntarily. To account for RECs performed in regulated states, EPA subsumed emissions reductions and compliance costs in states where these completion-related emissions are already controlled into the baseline. Additionally, based on public comments and reports to EPA's Natural Gas STAR program, EPA recognizes that some producers conduct well completions using REC techniques voluntarily for economic and/or environmental objectives as a normal part of business. To account for emissions reductions and costs arising from voluntary implementation of pollution controls EPA used information on total emission reductions reported to the EPA by partners of the EPA Natural Gas STAR. This estimate of this voluntary REC activity in the absence of regulation is also included in the baseline. More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket.

The analysis of energy system impacts for the final NSPS under the primary baseline shows that domestic natural gas production is not likely to change in 2015, the year used in the

RIA to analyze impacts. Average natural gas prices are also not estimated to change in response to the final rules. Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.01/barrel or about 0.01 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars. The NEMS-based analysis estimates in the year of analysis, 2015, that net imports of natural gas and crude oil will not change.

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.

For more information on the estimated energy effects of this final rule, please see Section 7 of this RIA.

5.9 National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA of 1995, Public Law 104–113, 12(d) (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 bodies. The NTTAA directs the EPA to provide Congress, through OMB, explanations when the EPA decides not to use available and applicable VCS.

This final action does not involve technical standards. Therefore, the EPA is not considering the use of any VCS.

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. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice 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.

The EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low-income, or indigenous populations.

To examine the potential for any environmental justice issues that might be associated with each source category, we evaluated the percentages of various social, demographic, and economic groups within the at-risk population living near the facilities where these source categories are located and compared them to national averages. The development of demographic analyses to inform the consideration of environmental justice issues in the EPA rulemakings is an evolving science.

The EPA conducted a demographic analysis, focusing on populations within 50 km of any facility in each of the source categories that are estimated to have HAP exposures which result in cancer risks of 1-in-1 million or greater or non-cancer hazard indices of 1 or greater based on estimates of current HAP emissions. The results of this analysis are documented in the technical report: Risk and Technology Review – Analysis of Socio-economic Factors for Populations Living Near Oil & Natural Gas Production Facilities located in the docket for this rulemaking.

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 non-cancer 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.

To promote meaningful involvement, the EPA conducted three public hearings on the proposal. The hearings were held in Pittsburgh, Pennsylvania, on September 27, 2011, Denver, Colorado, on September 28, 2011, and Arlington, Texas, on September 29, 2011. A total of 261 people spoke at the three hearings and 735 people attended the hearings. The attendees at the hearings included private citizens, community-based and environmental organizations, industry representatives, associations representing industry and local and state government officials.

5.11 Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this final rule and other required information to the United States Senate, the United States House of Representatives, and the Comptroller General of the United States prior to publication of the final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a "major rule" as defined by 5 U.S.C. 804(2).

6 COMPARISON OF BENEFITS AND COSTS

Because we are unable to estimate the monetary value of the emissions reductions from the 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 annualized engineering cost of the final NSPS in the analysis year of 2015 when the additional natural gas and condensate recovery is included in the analysis is estimated at -$15 million. EPA anticipates that this rule would prevent 190,000 tons of VOC, 1.0 million tons of methane, and 11,000 tons of HAP in 2015 from new sources. In 2015, EPA estimates the annualized costs for the NESHAP Amendments to be 3.5 million.[68] EPA anticipates that this rule would reduce 1,200 tons of VOC, 420 tons of methane, and 670 tons of HAP in 2015 from existing sources. For the NESHAP Amendments, a break-even analysis suggests that HAP emissions would need to be valued at $5,200 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 $2,900 per ton or the methane emissions would need to be valued at $8,300 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

For the final 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 of natural

[68] See Section 3 of this RIA for more information regarding the cost estimates for the NESHAP.

gas would need to be at least $3.66 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 $4.22 per Mcf in 2015. In addition to the revenue from product recovery, the NSPS would avert emissions of VOC, HAP, 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, VOC would need to be valued at about $150 per ton for the benefits to exceed the costs. All estimates are in 2008 dollars.

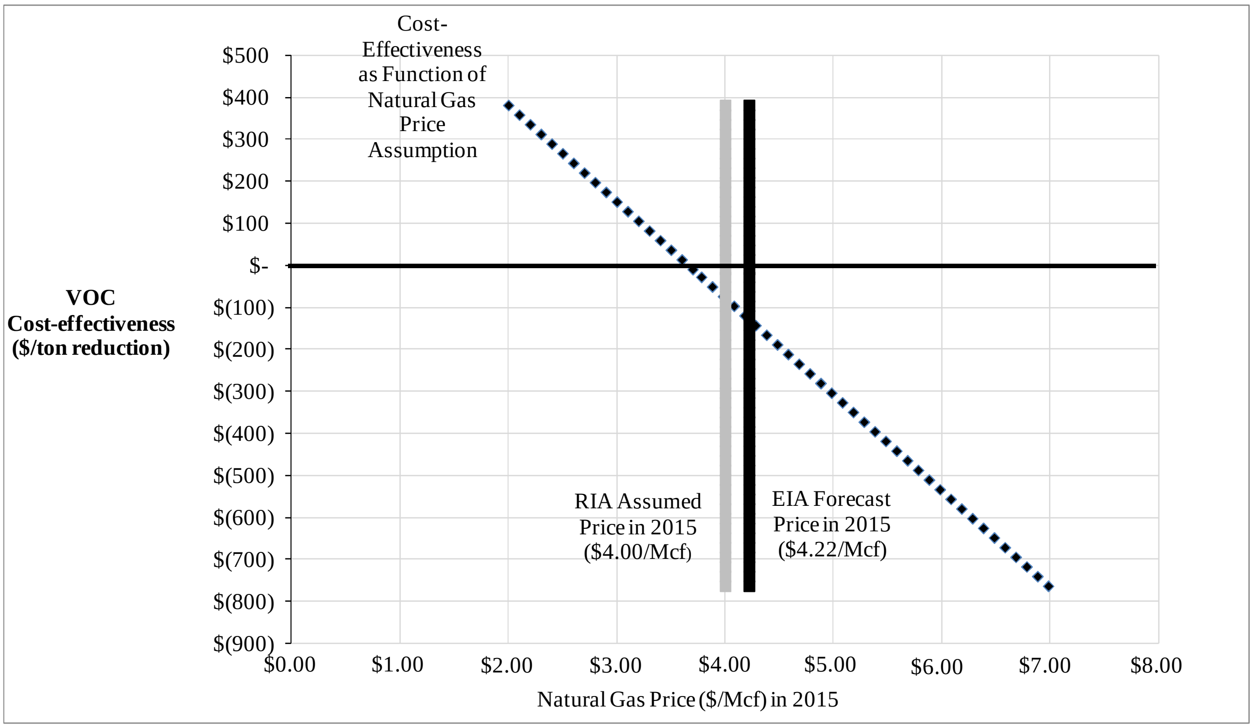

Figure 6-1 Illustrative Break-Even Diagram for Alternate Natural Gas Prices for the NSPS

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.[69] In addition, ozone benefits have been previously valued at $240 to $1,000 per ton of VOC reduced.

[69] 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.

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., VOC 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, HAP, and methane.

Table 6-1 and Table 6-2 present the summary of the benefits, costs, and net benefits for the NSPS and NESHAP Amendments, respectively. The NSPS analysis assumes that RECs performed voluntarily or in States where these emissions are already regulated would continue in absence of Federal regulation. Table 6-3 provides a summary of the direct and secondary emissions changes for each rule.

Table 6-1 Summary of the Monetized Benefits, Costs, and Net Benefits for the Final Oil and Natural Gas NSPS in 2015[1]

	Final[4]
Total Monetized Benefits[2]	N/A
Total Costs[3]	-$15 million
Net Benefits	N/A
Non-monetized Benefits	11,000 tons of HAP[5] 190,000 tons of VOC 1.0 million tons of methane Health effects of HAP exposure[5] Health effects of $PM_{2.5}$ and ozone exposure Visibility impairment Vegetation effects 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 HAP, 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 final NSPS are anticipated to have minor secondary disbenefits, including an increase of 1.1 million tons of carbon dioxide (CO_2), 550 tons of nitrogen oxides (NOx), 19 tons of PM, 3,000 tons of CO, and 1,100 tons of total hydrocarbons (THC) as well as emission reductions associated with the energy system impacts. The net CO_2-equivalent ($CO_{2\text{-}e}$) emission reductions are 18 million metric tons**.**

[3] The engineering compliance costs are annualized using a 7 percent discount rate.

[4] The negative cost for the NSPS reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the final 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 HAP and climate effects are co-benefits.

Table 6-2 Summary of the Monetized Benefits, Costs, and Net Benefits for the Final Oil and Natural Gas NESHAP Amendments in 2015[1]

	Final
Total Monetized Benefits[2]	N/A
Total Costs[3]	$3.5
Net Benefits	N/A
Non-monetized Benefits[5]	670 tons of HAP
	1,200 tons of VOC[4]
	420 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 HAP, 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.

[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.

[5] The specific control technologies for the NESHAP are anticipated to have minor secondary disbenefits, but EPA was unable to estimate these secondary disbenefits. The net CO_2-equivalent emission reductions are 8,000 metric tons.

Table 6-3 Summary of Emissions Changes for the Final Oil and Gas NSPS and NESHAP in 2015 (short tons per year)

	Pollutant	NSPS	NESHAP
Change in Direct Emissions	VOC	-190,000	-670
	Methane	-1,000,000	-1,200
	HAP	-11,000	-420
Change in Secondary Emissions (Producer-Side) [1]	CO_2	1,100,000	N/A
	NOx	550	N/A
	PM	19	N/A
	CO	3,000	N/A
	THC	1,100	N/A
Change in Secondary Emissions (Consumer-Side)	CO_2-e	720,000	N/A
Net Change in CO_2-equivalent Emissions	CO_2-e (short tons)	-19,000,000	-8,800
	CO_2-e (metric tons)	-18,000,000	-8,000

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 Final NSPS and NESHAP Amendments

We use the National Energy Modeling System (NEMS) to estimate the impacts of the final NSPS and NESHAP Amendments 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 final rules 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 the 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 final rules shows that about 92 percent of the natural gas captured by emissions controls suggested by the rule is captured by performing REC 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 REC 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 (DOE). 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 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>.

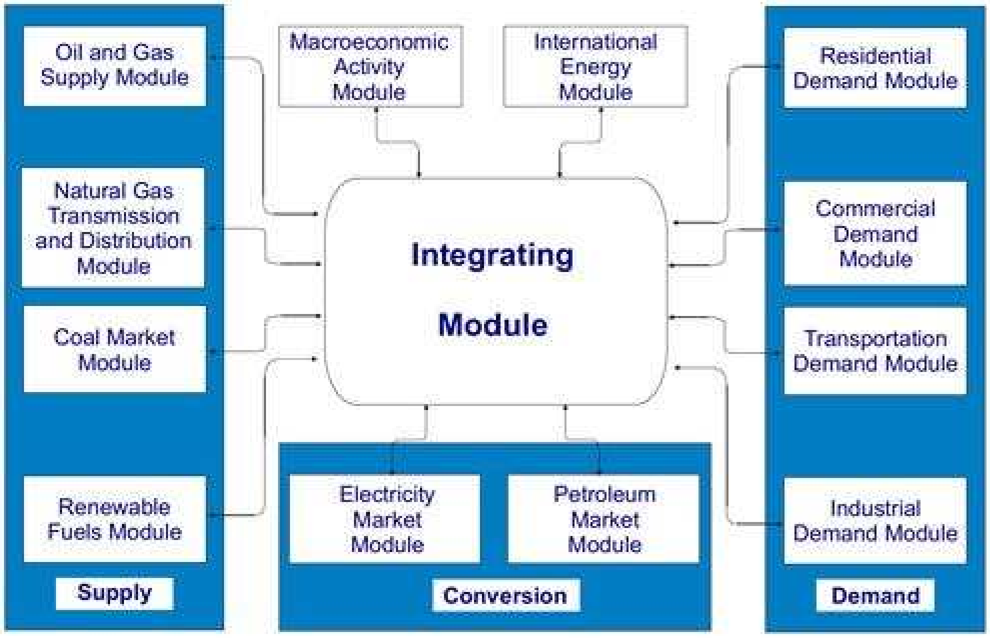

Figure 7-1 Organization of NEMS Modules (source: U.S. Energy Information Administration)

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.[70] The RIA baseline is consistent with that of the Annual Energy Outlook 2011 which is used extensively in Section 2 in the Industry Profile.

[70] 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 final rules, 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 final rules. We are able to target additional expenditures for environmental controls required by the NSPS and NESHAP Amendments 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 final rules. 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 is transported 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 required capital. A caveat to this is that the estimated unit-level capital costs of controls that are newly required at a national-level as a result of the regulation—REC, 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 NSPS. 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 3-4) by the appropriate number of expected new wells in the year of analysis. The result yields an approximation of 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 one hundred new wells drilled after the implementation the NSPS are recompleted using hydraulic fracturing 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
Equipment Leaks			
Processing Plants (NSPS)	Subpart VVa	$14	Natural Gas
Reciprocating Compressors			
Gathering and Boosting Stns. (NSPS)	AMM	$10	Natural Gas
Processing Plants (NSPS)	AMM	-$27	Natural Gas
Centrifugal Compressors			
Processing Plants (NSPS)	Route to control	-$35	Natural Gas
Pneumatic Controllers -			
Oil and Gas Production (NSPS)	Emission limits	$11/-$698	Oil/Natural Gas
Processing Plants (NSPS)	Emission limits	7.0	Natural Gas
Storage Vessels			
Emissions at least 6 tons per year (NSPS)	Emission limits	$203/$197	Oil/Natural Gas
Small Glycol Dehydrators			
Production and Transmission Segments (NESHAP)	Emission limits	$60/$60	Oil/Natural Gas
Reporting and Recordkeeping			
NSPS and NESHAP	N/A	$87/$60	Oil/Natural Gas

Table 7-2 Summary of Additional Per Completion/Recompletion Costs (2008$) for Environmental Controls Entered into NEMS

Emissions Sources/Points	Emissions Control	Per Completion Costs (2008$)	Wells Applied To in NEMS
Well Completions			
Hydraulically Fractured New Natural Gas Wells	REC/Combustion	-$271	New Tight Sand/ Shale Gas/CBM
Well Recompletions			
Hydraulically Refractured Existing Natural Gas Wells	REC/Combustion	-$604	Existing Tight Sand/ Shale Gas /Coalbed Methane

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 final NSPS.

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. For the final NSPS, we estimate that natural gas recovery is 2,473 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 this per-well natural gas recovery estimate is lower than the per-well estimate when RECs are implemented. The estimate is lower because we account for emissions that are combusted, REC 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 differently in that we estimated the natural gas recovery by natural gas resource type 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 to be about 3.4 bcf, with 1.6 bcf accruing to shale gas, 1.4 bcf accruing to tight sands, and 0.4 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 final NSPS and NESHAP Amendments 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 predicted results for 2015 under the final rules. For context, we provide estimates of production activities in 2011.

7.2.3.1 Impacts on Drilling Activities

Because the potential costs of the final rules 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.

Table 7-3 Successful Oil and Gas Wells Drilled, NSPS

		Future Scenario, 2015	
	2011	**Baseline**	**Under Final NSPS**
Successful Wells Drilled			
Natural Gas	16,373	19,097	19,162
Crude Oil	10,352	11,025	11,025
Total	**26,725**	**30,122**	**30,164**
% Change in Successful Wells Drilled from Baseline			
Natural Gas			0.34%
Crude Oil			0.00%
Total			**0.22%**

We estimate that the number of successful natural gas wells drilled increases slightly for the final NSPS, while the number of successful crude oil wells drilled does not change. The number of successful natural gas wells drilled is estimated to increase about 0.34%. 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 NSPS, 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 number of successful wells drilled increase in tight sands, shale gas, as well as coalbed methane.

Table 7-4 Successful Wells Drilled by Well Type (Onshore, Lower 48 States), NSPS

		Future Scenario, 2015	
	2011	**Baseline**	**Under Final NSPS**
Successful Wells Drilled			
Conventional Gas Wells	7,267	7,607	7,607
Tight Sands	2,441	2,772	2,785
Shale Gas	5,007	7,022	7,066
Coalbed Methane	1,593	1,609	1,618
Total	**16,308**	**19,010**	**19,076**
% Change in Successful Wells Drilled from Baseline			
Conventional Gas Wells			0.00%
Tight Sands			0.47%
Shale Gas			0.63%
Coalbed Methane			0.56%
Total			**0.35%**

Well drilling in tight sands is estimated to increase slightly, about 0.47 percent. Drilling in shale gas is forecast to increase from the baseline by 0.63 percent. Wells in CBM reserves are also estimated to increase from the baseline by 0.56 percent.

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 final NSPS and NESHAP Amendments, as of 2015. Domestic natural gas and crude oil production are not forecast to change under the final rules, again because impacts of the rules are expected to be negligible.

Table 7-5 Annual Domestic Natural Gas and Crude Oil Production, NSPS

		Future Scenario, 2015	
	2011	**Baseline**	**Under Final NSPS**
Domestic Production			
Natural Gas (trillion cubic feet)	21.05	22.43	22.43
Crude Oil (million barrels/day)	5.46	5.81	5.81
Natural Gas			0.00%
Crude Oil			0.00%

The NEMS analysis estimates no 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 NSPS (approximately 43 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 post-rule equilibrium, producers implementing emissions controls still capture and sell approximately 43 bcf of natural gas. For example, as shown in Table 7-4, about 11,400 new unconventional natural gas wells are completed under the final NSPS; using assumptions from the engineering cost analysis about voluntary RECs performed, RECs required under State regulations and exploratory wells and relatively low pressure wells exempted from REC requirements, about 4,100 NSPS-required RECs would be performed on new natural gas well completions, according to the NEMS analysis, not including the recompletions of existing wells. This recovered natural gas substitutes for natural gas that would be produced from the ground absent the rule. In effect, then, the natural gas that would have been extracted and emitted into the atmosphere is left in the formation for future extraction, according to these results.

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. With the exception of tight sands, production from all types of wells is estimated to increase under the final rules. However, the decrease in production from tight sands is estimated to offset the slight production increases estimated in conventional, shale, and coalbed methane formations.

Table 7-6 Natural Gas Production by Well Type (Onshore, Lower 48 States), NSPS

	2011	Future Scenario, 2015 Baseline	Future Scenario, 2015 Under Final NSPS
Natural Gas Production by Well Type (trillion cubic feet)			
Conventional Gas Wells	4.06	3.74	3.75
Tight Sands	5.96	5.89	5.85
Shale Gas	5.21	7.20	7.24
Coalbed Methane	1.72	1.67	1.68
Total	**16.95**	**18.51**	**18.51**
% Change in Natural Gas Production by Well Type from Baseline			
Conventional Gas Wells			0.27%
Tight Sands			-0.68%
Shale Gas			0.56%
Coalbed Methane			0.60%
Total			**0.05%**

Note: Totals may not sum due to independent rounding.

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. Wellhead natural gas price are not forecast to change under the final rules, while crude oil prices are forecast to decrease slightly under the NSPS.

Table 7-7 Lower 48 Average Natural Gas and Crude Oil Wellhead Price, NSPS

	2011	Future Scenario, 2015 Baseline	Future Scenario, 2015 Under Final NSPS
Lower 48 Average Wellhead Price			
Natural Gas (2008$ per Mcf)	4.07	4.22	4.22
Crude Oil (2008$ per barrel)	83.65	94.60	94.59
% Change in Lower 48 Average Wellhead Price from Baseline			
Natural Gas			0.00%
Crude Oil			-0.01%

Table 7-8 presents estimates of the price of natural gas to final consumers in 2008 dollars per million BTU. Commercial and industrial sector consumers of natural gas are estimated to receive slight price increases, while the national average price to consumers of natural gas is not estimated to change.

Table 7-8 Delivered Natural Gas Prices by Sector (2008$ per million BTU), 2015, NSPS

		Future Scenario, 2015	
	2011	**Baseline**	**Under Final NSPS**
Delivered Prices (2008$ per million BTU)			
Residential	10.52	10.35	10.35
Commercial	9.26	8.56	8.57
Industrial	4.97	5.07	5.08
Electric Power	4.81	4.77	4.77
Transportation	12.30	12.24	12.24
Average	**6.76**	**6.59**	**6.59**
% Change in Delivered Prices from Baseline			
Residential			0.00%
Commercial			0.12%
Industrial			0.20%
Electric Power			0.00%
Transportation			0.00%
Average			**0.00%**

Final consumption of natural gas is not estimated to change in 2015 from the baseline under the final rules, 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

		Future Scenario, 2015	
	2011	**Baseline**	**Under Final NSPS**
Consumption (trillion cubic feet)			
Residential	4.76	4.81	4.81
Commercial	3.22	3.38	3.38
Industrial	6.95	8.05	8.06
Electric Power	7.00	6.98	6.97
Transportation	0.03	0.04	0.04
Pipeline Fuel	0.64	0.65	0.65
Lease and Plant Fuel	1.27	1.20	1.20
Total	**23.86**	**25.11**	**25.11**
% Change in Consumption from Baseline			
Residential			0.00%
Commercial			0.00%
Industrial			0.12%
Electric Power			-0.14%
Transportation			0.00%
Pipeline Fuel			0.00%
Lease and Plant Fuel			0.00%
Total			**0.00%**

Note: Totals may not sum due to independent rounding.

7.2.3.3 Impacts on Imports and National Fuel Mix

The NEMS modeling estimates that the impacts from the NSPS and NEHSAP Amendments are not sufficiently large to affect the trade balance of natural gas. As shown in Table 7-10, estimates of crude oil imports do not vary from the baseline in 2015 under the NSPS.

Table 7-10 Net Imports of Natural Gas and Crude Oil, NSPS

	2011	Future Scenario, 2015 Baseline	Future Scenario, 2015 Under Final NSPS
Net Imports			
Natural Gas (trillion cubic feet)	2.75	2.69	2.69
Crude Oil (million barrels/day)	9.13	8.70	8.70
% Change in Net Imports			
Natural Gas			0.00%
Crude Oil			0.00%

Meanwhile, net imports of natural gas are estimated to decrease about 10 bcf (0.37 percent) under the NSPS, as the increased production substitutes for imported natural gas.

Table 7-11 evaluates estimates of energy consumption by energy type at the national level for 2015, the year of analysis. The NSPS is estimated to have small effects at the national level. We estimate an increase in 0.01 quadrillion BTU in 2015, a 0.01 percent increase. The percent contribution of natural gas, coal, and biomass is projected to increase slightly in 2015.

Table 7-11 Total Energy Consumption by Energy Type (Quadrillion BTU), NSPS

		Future Scenario, 2015	
	2011	**Baseline**	**Under Final NSPS**
Consumption (quadrillion BTU)			
Liquid Fuels	37.41	39.10	39.10
Natural Gas	24.49	25.77	25.78
Coal	20.42	19.73	19.74
Nuclear Power	8.40	8.77	8.77
Hydropower	2.58	2.92	2.92
Biomass	2.98	3.27	3.28
Other Renewable Energy	1.72	2.14	2.14
Other	0.30	0.31	0.31
Total	**98.29**	**102.02**	**102.03**
% Change in Consumption from Baseline			
Liquid Fuels			0.00%
Natural Gas			0.04%
Coal			0.05%
Nuclear Power			0.00%
Hydropower			0.00%
Biomass			0.31%
Other Renewable Energy			0.00%
Other			0.00%
Total			**0.01%**

Note: Totals may not sum due to independent rounding.

With the national profile of energy consumption estimated to change slightly under the NSPS 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 Scenario, 2015	
	2011	**Baseline**	**Under Final NSPS**
Energy-related CO_2-equivalent GHG Emissions (million metric tons CO_2-equivalent)			
Petroleum	2,359.59	2,433.60	2,433.53
Natural Gas	1,283.78	1,352.20	1,352.24
Coal	1,946.02	1,882.08	1,882.76
Other	11.99	11.99	11.99
Total	**5,601.39**	**5,679.87**	**5,680.52**
% Change in Energy-related CO_2-equivalent GHG Emissions from Baseline			
Petroleum			0.00%
Natural Gas			0.00%
Coal			0.04%
Other			0.00%
Total			**0.01%**

Note: Excludes "producer-side" emissions and emissions reductions estimated to result from NSPS. Totals may not sum due to independent rounding.

As is shown in Table 7-12, the final rules are predicted to slightly increase consumer-side aggregate energy-related CO_2-equivalent GHG emissions by about 650,000 metric tons (0.01 percent), mainly because consumer-side emissions from coal combustion increase slightly as a result of the slight consumption increases noted in Table 7-11.

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 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.[71] 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. Morgenstern et al. identified three separate components of the employment change in response to a regulation:

- Higher production costs raise market prices, higher prices reduce consumption (and production), reducing demand for labor within the regulated industry ("demand effect");

[71] In 2008, the industry totaled approximately $315 billion in revenues and 1.9 million employees including indirect employment effect; 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

- As costs go up, plants add more capital and labor. For example, pollution abatement activities require additional labor services to produce the same level of output ("cost effect");
- Post-regulation production technologies may be more or less labor intensive (i.e., more/less labor is required per dollar of output) ("factor-shift effect").

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.

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.

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 final 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. To the extent, however, that these rules may require unprofitable investments for some operators, there is a possibility that these producers decrease output in response and create downward pressure on labor demand, both in the regulated sector and on those sectors using natural gas as an input. This RIA excludes these potential adverse effects on the labor market.

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 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 final NSPS and in Table 7-14 for the final 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 final 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 50 FTEs for the final NSPS and about 4 FTEs for the final 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 570 FTEs for the final NSPS and about 30 FTEs for the final 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 final rules: implementing reduced emissions completions (REC) and reporting and recordkeeping requirements for the final 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 500 FTE, about 87 percent of the total continuing labor requirements for the final NSPS.[72] 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. 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.

[72] 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.

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 finalized Mercury and Air Toxics Standards, promulgated on December 16, 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.

Using plant-level Census 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 did not necessarily cause economically significant employment changes in those industries at that time.

For this version of the RIA for the final 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 the final rules. We believe the transfer of parameter estimates from the Morgenstern et al. study to the final 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, NSPS, 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
Well Completions and Recompletions								
New Hydraulically Fractured Gas Wells	REC/Combustion	4,107	0	218	0	893,397	0	430
New Hydraulically Fractured Gas Wells	Combustion	1,377	0	22	0	29,719	0	14
Hydraulically Re-fractured Gas Wells	REC/Combustion	532	0	218	0	115,721	0	56
Hydraulically Re-fractured Gas Wells	Combustion	121	0	22	0	2,611	0	1
Equipment Leaks								
Processing Plants	NSPS Subpart VVA	29	587	887	17,023	25,723	8	12
Reciprocating Compressors								
Gathering and Boosting Stations	Annual Monitoring/ Maintenance (AMM)	210	1	1	210	210	< 1	< 1
Processing Plants	AMM	209	1	1	209	209	< 1	< 1
Centrifugal Compressors								
Processing Plants	Route to Control	13	355	0	4,615	0	2	0
Pneumatic Controllers								
Oil and Gas Production	Low Bleed/Route to Process	13,632	0	0	0	0	0	0
Storage Vessels								
Emissions at least 6 tons per year	95% control	304	271	190	82,279	57,582	40	28
Reporting and Recordkeeping for Complete NSPS		All	N/A	N/A	0	68,882	0.0	33
TOTAL		**N/A**	**N/A**	**N/A**	**104,336**	**1,194,055**	**50**	**574**

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, Final NESHAP Amendments, 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	74	27	285	2,000	21,120	1	10
Transmission	Combustion devices, recovery devices, process modifications	7	27	285	189	1,998	<1	1
Reporting and Recordkeeping for Complete NESHAP Amendments		N/A	N/A	N/A	6,442	38,923	3	19
TOTAL		**81**	**N/A**	**N/A**	**8,631**	**62,040**	**4**	**30**

Note: Full-time equivalents (FTE) are estimated by first multiplying the projected number of affected units by 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 final 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 final 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 industry (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 final NSPS and because the segments of the oil and natural gas industry affected by the rules 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 final 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 final 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 final rules on small entities for both the NESHAP Amendments and NSPS, the analysis indicates that these 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 final 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 as a result of the final NSPS. However, not all components of the final 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. Unlike the controls for the final NSPS, the controls evaluated under the final NESHAP Amendments do not recover significant quantities of natural gas products.

This small entity impacts analysis uses the primary baseline used for the impacts analysis of our NSPS. This primary baseline takes into account RECs conducted pursuant to state regulations covering these operations and estimates of RECs performed voluntarily. To estimate emissions reductions and compliance costs arising from these voluntary RECs, EPA used information reported to EPA by partners of the EPA Natural Gas STAR. More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket[73], as well as in Section 3 of this RIA.

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

[73] "Voluntary Reductions from Gas Well Completions with Hydraulic Fracturing" in U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution: Background Supplemental Technical Support Document for the Final New Source Performance Standards. EPA-453/R-11-002. April 2012.

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.[74] 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).

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 analyses, and the terms are used interchangeably.

[74]See http://www.census.gov/csd/susb/ and http://www.sba.gov/advocacy/ for additional details.

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

			Percent of Firms		
NAICS	NAICS Description	Total Firms	Small Businesses	Large Businesses	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 final 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 final 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 focus 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 the 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. (IHS 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 of 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 final 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 final 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 final 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 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 impacted by the rules. The approaches taken for the NSPS and NESHAP Amendments differed; more detail on approaches for each set of 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[75] and is consistent with guidance published by the U.S. SBA’s Office of Advocacy that suggests that cost as a percentage

[75] 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).[76]

7.4.3 Small Entity Economic Impact Analysis, Final NSPS

7.4.3.1 Overview of Sample Data and Methods

The final 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)[77] as described in the Industry Profile in Section 2. Although the proportion of small firms in the OGJ 150 is smaller than the proportion evaluated by the Census Bureau's 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. The Census SUSB provides aggregated totals for all businesses in a particular NAICS code. It is not possible to use these data to identify those firms that actually drill wells or specific financial information for individual firms.

The OGJ 150 includes all public firms incorporated in the U.S. with reserves in the U.S. While the OGJ 150 lists only public firms, we believe the list is reasonably representative of the

[76] 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.

[77] Oil and Gas Journal. "OGJ150 Financial Results Down in '09; Production, Reserves Up." September 6, 2010 and Oil and Gas Journal. "OGJ150." September 21, 2009.

larger population of public and private firms operating in this segment of the industry. The sample of firms represented by the OGJ 150 accounts for 62% of the gas wells drilled in 2008 and 2009. While the population of firms responsible for the remaining 38% of gas wells may include some small private firms, there are also a number of large private companies and foreign firms not represented in the OGJ 150. Examples of companies that are not included in the OGJ 150, but that are likely responsible for a large number of hydraulically fractured natural gas well completions include BP, Encana, and Royal Dutch Shell.

To further examine the representativeness of the sample, EPA compared the revenues reported for the OGJ 150 to those reported for small firms in the Census Bureau's SUSB. While the average revenues in the OGJ 150 appear significantly larger than those in the Census Bureau's SUSB, this comparison is misleading. First, the OGJ 150 reports pre-tax revenues, which we would expect to be higher in every instance than the post-tax Census Bureau's SUSB receipts.[78] Additionally, due to the size of the sample, the descriptive statistics for the OGJ 150 may be influenced by a few particularly large data points. For example, for firms with 10 to 19 employees, removing one firm from the OGJ 150 sample decreases the average revenue for the group by approximately 38 percent. The result is roughly equal to the Census SUSB average for the same group, even before any adjustment for taxes. We believe that, despite these outliers, the data for the OGJ 150 are generally representative of the population in this industry.

While the Census SUSB data includes a greater proportion of very small firms (0-4 employees) than the OGJ 150 sample, we believe this sample appropriately reflects the industry for a number of reasons. First, the OGJ 150 includes companies of a range of sizes, from 1 to over 1 million employees. While there is generally a relationship between size and revenues, this does not necessarily hold true when examining the impacts on individual firms. In some cases, a firm with relatively few employees may have higher revenues than a much larger firm. Additionally, there is not necessarily a relationship between the size of a firm and the proportion of its costs to revenues. Finally, as discussed above, it is impossible to determine what portion of

[78] Census SUSB 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 excludes all revenue collected for local, state, and federal taxes. http://www.census.gov//econ/susb/definitions.html

the firms in the Census SUSB would be affected firms under the NSPS provisions related to completions of hydraulically fractured and refractured natural gas wells.

In the analysis that follows, we present median, minimum, and maximum values in addition to the average to provide readers with a more complete understanding of the firms in the sample. We are not able to compare these additional statistics to the Census Bureau's SUSB due to the aggregated nature of those data. When making a SISNOSE determination, we calculate the sales test ratio at the firm level, rather than as an average as is reported by the Census SUSB. By using this methodology, we ensure that the results reflect the impacts to all firms in the sample and are not skewed by unusually large data points.

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.

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[79] 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.[80] For these firms, we also used the American Business Directory and corporate websites to best identify the ultimate owner of the facilities or companies. These firms represent all potentially impacted firms in these segments, not a sample.

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[79] Oil and Gas Journal. "Special Report: Worldwide Gas Processing: New Plants, Data Push Global Gas Processing Capacity Ahead in 2009." June 7, 2010.
[80] Oil and Gas Journal. "Natural Gas Pipelines Continue Growth Despite Lower Earnings; Oil Profits Grow." November 1, 2010.

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 final NSPS in 2015 assuming their 2015 production activities were similar to those in 2008 and 2009. We estimate that 127 (46 percent) of these firms are small according to SBA criteria. We estimate 119 firms (43 percent) are not small firms according to SBA criteria. We are unable to classify the remaining 28 firms (10 percent) because of a lack of required information on employee counts or revenue estimates.

Table 7-18 shows the estimated revenues for 246 firms for which we have sufficient data that would be potentially affected by the final 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.

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	77	18,451.9	239.6	76.3	0.1	1,116.9
Large	47	1,345,292.0	28623.2	1,788.3	12.9	310,586.0
Subtotal	124	1,363,743.9	10,997.9	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	**127**	**24,118.5**	**189.9**	**34.9**	**0.1**	**1,459.1**
Large	**119**	**1,864,342.8**	**16,071.9**	**1,672.1**	**7.1**	**310,586.0**
Total	**246**	**1,888,461.3**	**7,771.4**	**164.9**	**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 (117 of the 124 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	74	13,262.9	179.2	60.4	0.1	2,401.9
Large	43	127,505.6	2,965.2	982.7	0.1	22,518.7
Total	**117**	**140,768.5**	**1,203.1**	**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 117 firms were approximately $140 billion in 2008 dollars). About 9 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 6 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

Well Type	Firm Size	Number of Firms	Estimated Average Wells Natural Gas and Crude Oil Wells Drilled (2008 and 2009) Total	Average	Median	Minimum	Maximum
Natural Gas							
	Small	77	2,049.5	26.6	5.7	0.2	259.3
	Large	44	9,723.1	221.0	153.2	0.6	868.3
	Subtotal	121	11,772.5	97.3	28.3	0.2	868.3
Crude Oil							
	Small	77	1179.6	15.3	3.3	0.1	149.2
	Large	44	5596.3	127.2	88.1	0.4	499.7
	Subtotal	121	6,775.9	56.0	16.3	0.1	499.7
Total							
	Small	**77**	**3,229.1**	**41.9**	**9.0**	**0.3**	**408.5**
	Large	**44**	**15,319.4**	**348.2**	**241.3**	**1.0**	**1,368.0**
	Total	**121**	**18,548.4**	**153.3**	**44.6**	**0.3**	**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 approximately 6 natural gas wells compared to 153 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 REC.

Unlike the analysis of regulatory impacts on small entities 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 estimated 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 final 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 controls.

This estimation procedure yielded an estimate of crude oil well compliance costs of $260 per drilled well and natural gas well compliance costs of $8,800 or less than 1 percent of the average costs of drilling a well according to EIA (see Table 2-8) without considering estimated revenues from product recovery and $260 and -$940 per drilled crude oil and natural gas well, respectively, 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 final 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 by 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 $5.0 million with estimated revenues from product recovery, respectively, in 2008 dollars, or about $20/MMcf without revenues and $14/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 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 $6.0 million without estimated revenues from product recovery and $5.9 million with estimated revenues from product recovery, respectively, in 2008 dollars.

7.4.3.2 Small Entity Impact Analysis, Final 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 $117 million in 2008 dollars, about 69 percent of the estimated annualized costs of the final NSPS without including revenues from additional product recovery of $116 million. When including revenues from additional product recovery, the estimated compliance costs for the firms in the sample are about $1.1 million.

Table 7-21 presents the distribution of estimated final NSPS compliance costs across firm size for the firms within our sample. Evident from this table, about 92 percent of the estimated engineering compliance costs accrue to the integrated and production segment of the industry, again explained by the fact that completion-related requirements contribute the bulk of the estimated engineering compliance costs (as well as estimated emissions reductions). About 16 percent of the total estimated engineering compliance costs (and about 16 percent of the costs accruing to the integrated and production segment) are concentrated on small firms.

Table 7-21 Distribution of Estimated Final NSPS Compliance Costs Without Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

Firm Type/Size	Number of Firms	Estimated Engineering Compliance Costs Without Estimated Revenues from Natural Gas Product Recovery (2008 dollars)				
		Total	Average	Median	Minimum	Maximum
Production and Integrated						
Small	77	17,795,916	231,116	48,134	749	2,299,042
Large	47	90,671,503	1,929,181	1,361,483	10,325	7,710,293
Subtotal	124	108,467,419	874,737	221,017	749	7,710,293
Pipeline						
Small	11	3,738	340	123	20	1,264
Large	36	1,641,771	45,605	4,218	41	994,491
Subtotal	47	1,645,509	35,011	2,498	20	994,491
Processing						
Small	39	482,232	12,365	1,906	191	279,864
Large	23	870,458	37,846	8,236	38	429,043
Subtotal	62	1,352,690	21,818	2,764	38	429,043
Pipelines/Processing						
Small	0	---	---	---	---	---
Large	13	5,828,374	448,336	159,519	2,040	2,892,799
Subtotal	13	5,828,374	448,336	159,519	2,040	2,892,799
Total						
Small	**127**	**18,281,886**	**143,952**	**13,602**	**20**	**2,299,042**
Large	**119**	**99,012,106**	**832,035**	**48,054**	**38**	**7,710,293**
Total	**246**	**117,293,992**	**476,805**	**22,225**	**20**	**7,710,293**

These distributions are similar when the revenues from expected natural gas recovery are included (Table 7-22). A total savings from the final NSPS of about $1.1 million is expected to accrue to small firms (about 23 percent of the savings to the integrated and production segment accrue to small firms), while large firms are expected to have a total cost of $2.3 million. 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 final NSPS.

Table 7-22 Distribution of Estimated Final NSPS Compliance Costs With Revenues from Additional Natural Gas Product Recovery across Firm Size in Sample of Firms

Firm Type/Size	Number of Firms	Estimated Engineering Compliance Costs With Estimated Revenues from Natural Gas Product Recovery (millions, 2008 dollars)				
		Total	Average	Median	Minimum	Maximum
Production and Integrated						
Small	77	-1,500,434	-19,486	25	-218,672	23,982
Large	47	-5,137,073	-109,299	-108,363	-721,121	924,574
Subtotal	124	-6,637,507	-53,528	-11,873	-721,121	924,574
Pipeline						
Small	11	3,629	330	119	19	1,226
Large	36	1,593,661	44,268	4,095	40	965,348
Subtotal	47	1,597,289	33,985	2,425	19	965,348
Processing						
Small	39	349,635	8,965	1,382	138	202,911
Large	23	631,112	27,440	5,971	28	311,071
Subtotal	62	980,747	15,819	2,004	28	311,071
Pipelines/Processing						
Small	0	---	---	---	---	---
Large	13	5,198,212	399,862	143,446	1,511	2,777,165
Subtotal	13	5,198,212	399,862	143,446	1,511	2,777,165
Total						
Small	**127**	**-1,147,170**	**-9,033**	**207**	**-218,672**	**202,911**
Large	**119**	**2,285,911**	**19,209**	**2,419**	**-721,121**	**2,777,165**
Total	**246**	**1,138,741**	**4,629**	**343**	**-721,121**	**2,777,165**

Table 7-23 Summary of Sales Test Ratios, Without Revenues from Additional Natural Gas Product Recovery for Firms Affected by Final NSPS

Firm Type/Size	Number of Firms	Descriptive Statistics for Sales Test Ratio Without Estimated Revenues from Natural Gas Product Recovery (%)			
		Average	Median	Minimum	Maximum
Production and Integrated					
Small	77	0.49%	0.11%	0.00%	11.86%
Large	47	0.10%	0.07%	0.00%	0.65%
Subtotal	124	0.34%	0.09%	0.00%	11.86%
Pipeline					
Small	11	0.01%	0.00%	0.00%	0.01%
Large	36	0.01%	0.00%	0.00%	0.06%
Subtotal	47	0.01%	0.00%	0.00%	0.06%
Processing					
Small	39	0.02%	0.01%	0.00%	0.16%
Large	23	0.01%	0.00%	0.00%	0.16%
Subtotal	62	0.02%	0.01%	0.00%	0.16%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	0.00%	0.00%	0.00%	0.01%
Subtotal	13	0.00%	0.00%	0.00%	0.01%
Total					
Small	**127**	**0.30%**	**0.04%**	**0.00%**	**11.86%**
Large	**119**	**0.05%**	**0.01%**	**0.00%**	**0.65%**
Total	**246**	**0.18%**	**0.02%**	**0.00%**	**11.86%**

The mean cost-sales ratio for all businesses when estimated product recovery is excluded from the analysis of the sample data is 0.18 percent, with a median ratio of 0.02 percent, a minimum of less than 0.01 percent, and a maximum of over 11 percent (Table 7-23). For small firms in the sample, the mean and median cost-sales ratios are 0.30 percent and 0.04 percent, respectively, with a minimum of less than 0.01 percent and a maximum of over 11 percent (Table 7-23). Each of these statistics indicates that, when considered in the aggregate, impacts are relatively higher on small firms than on 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 Final NSPS

Firm Type/Size	Number of Firms	Descriptive Statistics for Sales Test Ratio With Estimated Revenues from Natural Gas Product Recovery (%)			
		Average	Median	Minimum	Maximum
Production and Integrated					
Small	77	-0.01%	0.00%	-0.85%	0.40%
Large	47	0.00%	0.00%	-0.06%	0.14%
Subtotal	124	-0.01%	0.00%	-0.85%	0.40%
Pipeline					
Small	11	0.01%	0.00%	0.00%	0.01%
Large	36	0.01%	0.00%	0.00%	0.06%
Subtotal	47	0.01%	0.00%	0.00%	0.06%
Processing					
Small	39	0.01%	0.01%	0.00%	0.11%
Large	23	0.01%	0.00%	0.00%	0.11%
Subtotal	62	0.01%	0.00%	0.00%	0.11%
Pipelines/Processing					
Small	0	---	---	---	---
Large	13	0.00%	0.00%	0.00%	0.01%
Subtotal	13	0.00%	0.00%	0.00%	0.01%
Total					
Small	**127**	**0.00%**	**0.00%**	**-0.85%**	**0.40%**
Large	**119**	**0.00%**	**0.00%**	**-0.06%**	**0.14%**
Total	**246**	**0.00%**	**0.00%**	**-0.85%**	**0.40%**

The mean cost-sales ratio for all businesses when estimated product recovery is included is in the sample is less than 0.01 percent, with a median ratio of less than 0.01 percent, a minimum of -0.85 percent, and a maximum of 0.40 percent (Table 7-24). For small firms in the sample, the mean and median cost-sales ratios are less than 0.01 percent and less than 0.01 percent, respectively, with a minimum of -0.85 percent and a maximum of 0.40 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 of the 127 firms (100 percent) have estimated cost-sales ratios 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 Final 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%	123	96.9%	127	100.0%
C/S Ratio 1-3%	1	0.8%	0	0.0%
CS Ratio greater than 3%	3	2.4%	0	0.0%

When the estimated revenues from product recovery are not included in the analysis, one firm (less than 1 percent) is estimated to have sales test ratios between 1 and 3 percent. Three firms (less than 3 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 REC 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 final NSPS.

7.4.3.3 Small Entity Impact Analysis, Final NSPS, Additional Qualitative Discussion

7.4.3.3.1 Small Entities and Reduced Emissions Completions

Because REC requirements of the final 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, and 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 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 a REC, a service provider 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 typically automatically read daily, 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, is that 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. To the extent there is a lag between a REC expenditures and receipt of revenue from recovered products, we believe the impact on cash flows would be minimal.

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 that 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.

There are situations in which operators, large or small, may face constraints in directing captured gas to the gathering lines or pipelines. In these instances, this rule provides the flexibility to combust completion emissions rather than performing a REC.

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 final NSPS.

7.4.3.3.2 Age of Equipment and Final 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 requirements of these rules 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 about $15 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 final NSPS relate to well completion activities at new hydraulically fractured natural gas wells and existing wells that are recompleted after being fractured or re-fractured. These requirements constitute the bulk of the expected engineering compliance expenditures (about $320 million in annualized costs) and expected revenues from natural gas product recovery (about $330 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.

7.4.4 Small Entity Economic Impact Analysis, Final NESHAP Amendments

The Final 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 sales ratio to identify small businesses that might be significantly impacted by the NESHAP.

While we were able to identify the owners of all but 9 facilities likely to be affected, we could not obtain employment and revenue levels for all of these firms. Overall, we expect about 81 facilities to be affected, and these facilities are owned by an estimated 42 firms. We were unable to obtain financial information on 7 (16 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 35 firms for which we have financial information, we identified 11 small firms (31 percent) and 24 large firms (69 percent) that would be affected by the NESHAP Amendments. Annual compliance costs for small firms are estimated at $390,000 (22 percent of the total compliance costs), and annual compliance costs for large firms are estimated at $1.1 million (66 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 $200,000 (11percent of the total). All figures are in 2008 dollars.

The average estimated annualized compliance cost for the 11 small firms identified in the dataset is $35,000, while the mean annual revenue figure for the same firms is over $116 million, or less than 0.01 percent on average for all 10 firms (Table 7-26). The median sale-test ratio for these firms is smaller at 0.09 percent. Large firms are likely to see an average of $48,000 in annual compliance costs, whereas average revenue for these firms exceeds $29 billion since this set of firms includes many of the very large, integrated energy firms. For large firms, the average sales-test ratio is less than 0.01 percent, and the median sales-test ratio is also less than 0.01 percent (Table 7-26).

Table 7-26 Summary of Sales Test Ratios for Firms Affected by Final 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	11	31%	0.24%	0.09%	< 0.01%	0.93%
Large	24	69%	< 0.01%	< 0.01%	< 0.01%	0.01%
All	35	100%	0.08%	< 0.01%	< 0.01%	0.93%

Among the small firms, all are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues (Table 7-27). These firms represent a very small slice of the oil and gas industry in its entirety, less than 0.02 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, Final 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%	11	100.0%	0.17%
C/S Ratio 1-3%	0	0.0%	0.0%
CS Ratio greater than 3%	0	0.0%	0.0%

7.4.5 Conclusions for NSPS and NESHAP Amendments

While both the NSPS and NESHAP amendment would individually result in a no SISNOSE finding, the EPA performed an additional analysis in order to certify the rule in its entirety. This analysis compared compliance costs to entity revenues for the total of all the entities affected by the NESHAP Amendments and the sample of entities analyzed for the NSPS. When revenues from additional natural gas product sales are not included, 132 of the 136 small firms (97 percent) are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues (Table 7-28).

Meanwhile, four firms (3 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. When revenues from additional natural gas product sales are included, all 136 small firms (100 percent) are likely to have impacts of less than 1 percent.

Table 7-28 Affected Small Firms as a Percent of Small Firms Nationwide, Final NSPS and NESHAP Amendments

Impact Level	Without Estimated Revenues from Natural Gas Product Recovery		With Estimated Revenues from Natural Gas Product Recovery	
	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%	132	97.1%	136	100.0%
C/S Ratio 1-3%	1	0.7%	0	0.0%
CS Ratio greater than 3%	3	2.2%	0	0.0%

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.

7.5 References

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Radon in Natural Gas from Marcellus Shale
By Marvin Resnikoff, Radioactive Waste Management Associates
Executive Summary*
January 10, 2012

A significant public health hazard associated with drilling for natural gas in the Marcellus Shale formation must be seriously investigated by the New York State Department of Environmental Conservation (DEC). This hazard is from radioactive radon gas and the potential for large numbers of lung cancer among natural gas customers. This issue, which has been ignored in the DEC's Draft Supplemental Environmental Impact Statement, must be addressed in a revised Impact Statement and before DEC issues any drilling permits.

Unlike present sources for natural gas, located in Texas and Louisiana, the Marcellus Shale is considerably closer to New York consumers. In addition, the radioactive levels at the wellheads in New York are higher than the national average for natural gas wells throughout the US.

In this paper Radioactive Waste Management Associates calculates the wellhead concentrations of radon in natural gas from Marcellus Shale, the time to transit to consumers, particularly New York City residents, and the potential health effects of releasing radon, especially in the smaller living quarters found in urban areas.

It is well known that radon (radon-222) is present in natural gas.[1] Published reports by R H Johnson of the US Environmental Protection Agency[2] and C V Gogolak of the US Department of Energy[3] also address this issue. Radon is present in natural gas from Marcellus Shale at much higher concentrations than natural gas from wells in Louisiana and Texas.

Since radon is a decay product of radium-226, to calculate radon levels it is necessary to know the concentrations of radium-226, Based on a USGS study[4] and gamma ray logs (also known as GAPI logs) that we have examined, the radium concentrations in the

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* Great appreciation for the excellent assistance of Minard Hamilton, RWMA Associate

1 Agency for Toxic Substances and Disease Registry**,** *Toxicological Profile for Ionizing Radiation and* U.S. National Research Council, *Health, Risks of Radon and Other Internally Deposited Alpha-Emitters: BEIR IV* (National Academy Press, 1988)

2 Johnson,R.H. *et al,* "Assessment of Potential Radiological Health Effects from Radon in Natural Gas," Environmental Protection Agency, EPA-520-73-004, November 1973.

3 Gogolak, C.V., "Review of 222 Rn in Natural Gas Produced from Unconventional Sources," Department of Energy, DOE/EML-385, November 1980

4 J.S. Leventhal, J.G. Crock, and M.J. Malcolm, *Geochemistry of trace elements in Devonian shales of the Appalachian Basin*, U.S. Geological Survey Open File Report 81-778, 1981

Marcellus Shale is 8 to 32 times background. This compares to an average radium-226 in surface soil in New York State of 0.81 picoCuries per gram (pCi/g)[5]

Using this range of radium concentrations and a simple Fortran program that simulates the production of radon in the well bore, and transit to the wellhead, we calculate a range of radon concentrations at the wellhead between 36.9 picoCuries per liter (pCi/L) to 2576 pCi/L.

These wellhead concentrations in Marcellus shale are up to 70 times the average in natural gas wells throughout the U.S. The average was calculated by R.H.Johnson of the US Environmental Protection Agency in 1973 (pre-fracking) to be 37 pCi/L[6] to a maximum of 1450 pCi/L.

In addition, the distance to New York State apartments and homes from the Marcellus formation is 400 miles and sometimes less. This contrasts with the distance from the Gulf Coast and other formations which is 1800 miles. At 10 mph movement in the pipeline, natural gas containing the radioactive gas, radon, which has a half-life of 3.8 days, will have three times the radon concentrations than natural gas originating at the Gulf Coast., everything else being equal, which it is not..

Being an inert gas, radon will not be destroyed when natural gas is burned in a kitchen stove.

We have examined published dilution factors and factored in numbers for average urban apartments where the dilution factor and the number of air exchanges per hour are less than those of non-urban dwellings. This analysis implies that the radon concentrations in New York City and urban apartments is greater than the national average.

We assume a figure of 11.9 million residents affected. This figure is calculated in the following manner: Based on US Department of Energy figures our calculations assume 4.4 million gas stoves in New York State. This figure is multiplied by 2.69 persons per household to determine the number of residents affected: this number equals 11.9 million.

We calculate the number of excess lung cancer deaths for New York State. Our results: the potential number of fatal lung cancer deaths due to radon in natural gas from the Marcellus shale range from 1,182 to 30,448.

This is an additional number of lung cancer deaths due to radon from Marcellus Shale over deaths from natural radon already impacting New York State homes and their residents.

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[5] Myrick, T. E., et al. 1981. *State Background Radiation Levels: Results of Measurements Taken During 1975-1979*, ORNL/TM-7343, Oak Ridge, Tenn..
[6] Johnson, Op cit.

The Draft Supplemental Environmental Impact Statement produced by the New York State Department of Environmental Conservation needs to be revised to take into account this public health and environmental hazard. In the entire 1400 page statement there is only one sentence containing the word "radon" and no consideration of this significant public health hazard.

Further, NYDEC needs to independently calculate and measure radon at the wellhead from the Marcellus Shale formation in presently operating wells before issuing drilling permits in New York State. The present RDSGEIS should be withdrawn.

Introduction

It has been known for over 40 years that radon, a radioactive gas, is present in natural gas. Reports by R.H. Johnson[7] and C.V. Gogolak[8] calculate the health effects due to burning natural gas in kitchen stoves and space heaters. In an US Environmental Protection Agency report, Raymond Johnson calculates the number of lung cancer deaths due to inhalation of radon in homes throughout the U.S. as 95 due to radon concentrations in the pipeline of 37 pCi/L.

Radon is an inert radioactive gas. This means it does not react chemically with other elements. Whatever radon is in the pipeline and is delivered to homes is released to the home environment from kitchen stoves and space heaters. The radon is not oxidized and is not made benign or non-radioactive in the burning process.

Since radon is an inert gas, when it is inhaled, the gas is mostly exhaled. Except radon will decay to other radioactive decay products, such as polonium, bismuth and lead. These are solid fine radioactive particles that can be inhaled and subsequently reside in the lung.

Most calculations assume this radon gas mixes uniformly within the living space and the concentrations of radon and its decay products are thereby diluted. Thus, once radon enters the home, the average concentrations depend on the home volume, and also on the number of air interchanges. Previous calculations by Johnson and Gogolak make specific assumptions about the average volume of a home and the number of air interchanges per hour. Their assumptions are not necessarily appropriate to apartments in major urban areas, such as New York City.

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[7] Johnson,R.H. *et al,* "Assessment of Potential Radiological Health Effects from Radon in Natural Gas," Environmental Protection Agency, EPA-520-73-004, November 1973.

[8] Gogolak, C.V., "Review of 222 Rn in Natural Gas Produced from Unconventional Sources," Department of Energy, DOE/EML-385, November 1980

To estimate the health effects of radon in natural gas three factors must be addressed. One, the concentration of radon at the natural gas wellhead. Two, transport from the wellhead to the household. And, three, the dilution of incoming radon in the home.

The first step is to calculate the initial source term, the concentration of radon at the wellhead. The Marcellus shale formation is more radioactive than other sources of natural gas in the United States. Based on a simple model of a hydraulic fractured well, in the next section, we calculate the radon concentrations at the wellhead.

Radon at the wellhead is then transported through natural gas pipelines to distribution centers and to homes for use in cooking and heating. During the time of transport, radon decays. This radioactive gas has a half-life of 3.8 days.

Most of the natural gas currently consumed in New York State arrives from the Gulf Coast, a distance of 1800 miles. The closer to the point of use, the shorter the transport time. And the Marcellus shale is much closer, less than 400 miles to New York City. With a travel time of 10 mph in the pipeline, only about 25% of the initial radon from the Gulf Coast remains to enter homes. Since gas from the Marcellus shale travels a much shorter distance, a greater fraction remains. We estimate closer to 76% of the initial concentration of radon at Marcellus Shale wellheads will arrive at New York State residences.

Once radon enters the home through cooking, it is diluted within the home volume and also by air exchanges with the outside air. Radioactivity due to radon decay products is inhaled and resides in the lung, yielding a radiation dose to the lung. Using the latest dose conversion factors, based on ICRP-60, which convert the inhaled radioactivity to a radiation dose, we can calculate the radiation dose to an individual over a 30-year period. From the radiation dose to the population, we can determine the number of lung cancer deaths to New York State residents. As will be seen, the total number of lung cancers is significant, far more than estimated by Johnson in 1973.

None of this analysis appears in the Generic Environmental Impact Statement prepared by the New York Department of Environmental Conservation. In the entire 1400 page Environmental Impact Statement, one sentence appears. "Radon gas, which under most circumstances is the main human health concern from NORM, is produced by the decay of radium-226, which occurs in the uranium-238 decay chain."[9] (NORM refers to Naturally Occurring Radioactive Material.)

This one sentence is the full extent of the Department of Environmental Conservation's analysis of the environmental impact of radon.

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[9] Rdsgeis, p. 6-206.

Radon at the wellhead

In exploring for gas and oil in shale, the industry identifies natural gas formations by the high radioactivity and high carbon content at the Marcellus Shale horizon. Within the Marcellus Shale formation, the radioactive concentrations are 20 to 25 times background. However, the New York Department of Environmental Conservation (DEC) claims that "black shale typically contains trace levels of uranium and gamma ray logs indicate that this is true of the Marcellus shale."[10] Based on gamma ray logs, a study by the United States Geological Survey and statements in the Draft Supplemental Environmental Impact Statement, we differ strongly with the DEC assessment that the concentrations are "trace levels."

At RWMA, we analyzed the gamma-ray well logs from wells in three towns in New York State, Reading, Dix and Pulteney. The Pulteney well (also referred to as the Bergstresser well) would be used as a disposal well for radioactive waste water from other exploratory wells in New York State.[11] Gamma radioactivity within each well was sampled with a sensitive Geiger counter and the measurements were plotted on a graph as what are known as GAPI (Gamma-ray, American Petroleum Industry) units against depth.

The GAPI unit is defined by a calibration facility at the University of Houston, Texas. Located at this facility are three pits, each with a different mixture of thorium, uranium, and potassium. The actual GAPI unit is arbitrary. It is defined as 1/200th of the deflection measured between the high and low activity zones in the pits.[12] In order to convert the GAPI units to curies we used a method cited by several sources, in which 16.5 GAPI units equal 1 microgram of Radium-equivalent per metric ton (or 1 picocurie per gram).[13]

In general, the radioactivity throughout the depth of the bedrock appears to be equal to or less than 10 picocuries per gram (pCi/g). However, at certain depths in each well the radioactive activity is significantly higher.

All logs have a provision for the shifting of scale from the standard 0-200 GAPI range to greater than 200 GAPI or even greater than 400 GAPI. It is unclear from the logs how the shifting of scale is recorded, but at a certain depth the gamma ray line indicates measurements beyond the 0-200 GAPI range (Figure1).

In the three well logs in Figure 1, the y-axis represents the depth of the well in feet and the x-axis represents the gamma ray measurement in units of GAPI. The gamma ray

[10] Rdsgeis (2011), p, 4-29.
[11] Smith-Heavenrich S., 2010
[12] Hoppie, B.W. et al, 1994
[13] Donnez, 2007 p.33

radioactivity can be traced through the depth of the well by following the solid black line. At a certain point this line, which has been recording the gamma ray radioactivity within the 0-200 GAPI range, stops and traces curves that indicate measurements beyond this range for duration of a little less than 100 feet.

The measurements beyond the 0-200 GAPI range are found at the following depths: In the well log for the Reading, NY well (Shiavone 2), this occurs approximately between 1550 and 1650 feet, in the well log for Dixon, NY (WGI11) this occurs between 2400 and 2500 feet, and in the log for the Bergstresser well in Pulteney, NY we see it between 1700 and 1800 feet. These sections of increased radioactivity represent the Marcellus shale.

In each case the thickness (less than 100 feet) and the depth of the shale is consistent with the general geological predictions of the Marcellus formation in the region. It is not possible to give the specific radioactivity measurement due to the log quality, but if we consider that these sections indicate the gamma ray range of 200-400 GAPI, it would represent radioactive radium concentrations of about 12-24 pCi/g or higher. These radium concentrations are far higher than background radium concentrations in New York State[14], which are 0.85 pCi/g.

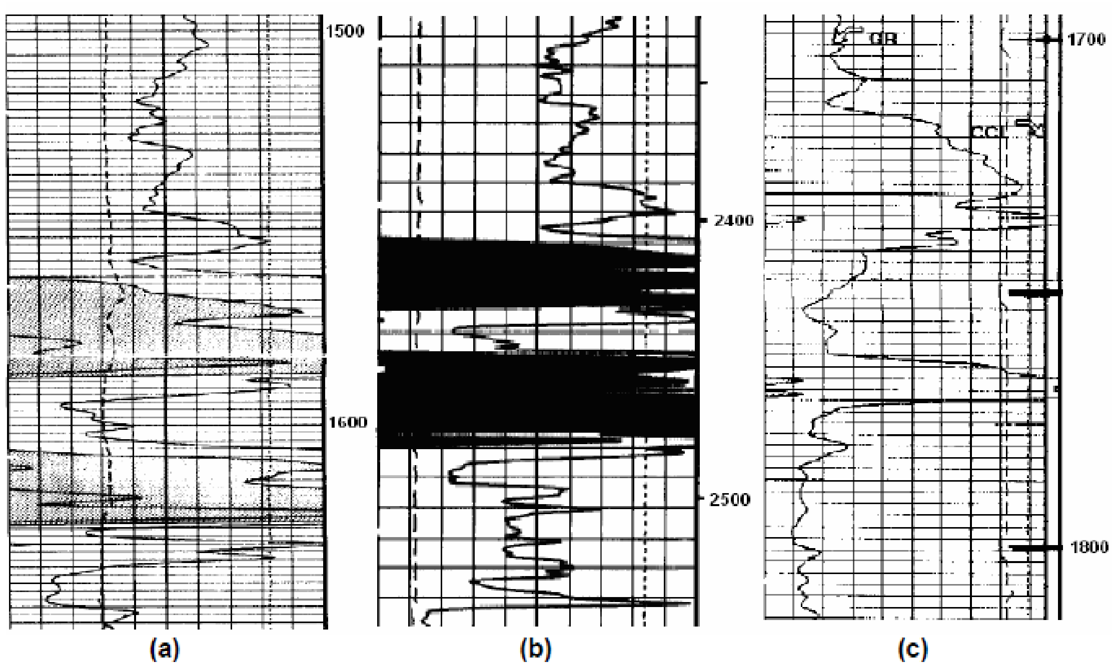

Figure 1. Excerpts from Gamma Ray Logs for (a) Shiavone 2 Well (Reading); (b) WGI11 Well (Dix); (c) Bergstresser Well (Pulteney)

[14] Myrik 1983

In 1981 the United States Geological Survey (USGS) performed a geochemical study of trace elements and uranium in the Devonian shale of the Appalachian Basin.[15] A brief review of this analysis is necessary to evaluate and verify the data provided by the GAPI logs for the three locations in New York State.

The Devonian layer refers to sediment formed 350 million years ago from mud in shallow seas. Since the layers do not form in a line parallel to the ground surface, the depth at which Marcellus is found can vary from surface outcroppings to as deep as 7,000 feet or more below the ground surface along the Pennsylvania border in the Delaware River valley,[16] and as deep as 9000 feet in Pennsylvania.[17]

The USGS study analyzed seventeen cores from wells in Pennsylvania, New York, Ohio, West Virginia, Kentucky, Tennessee, and Illinois. The researchers collected a variety of geochemical data to be used for resource assessment and identification of possible environmental problems. It is important to note the method of analyzing cores.

Rather than the direct gamma spectroscopy employed by CoPhysics[18], in the USGS study uranium was measured in each core with a more appropriate and precise method. This is called delayed-neutron analysis. In contrast, the oil and gas industry hired, CoPhysics, a non-ELAP-certified lab, it cannot do this more precise analysis. Nevertheless, DEC or its contractor, Alpha Environmental, quotes these measurements in Appendix 1. The Alpha Environmental report does not even cite the USGS study. Since USGS is a reputable and objective government agency, DEC should request an explanation why this reference was omitted.

Although the cores varied in thickness and in depth, geologists identified the Marcellus Shale stratum in several cores using data on the organic matter (carbon), sulfur, and uranium content of the samples. Table 1 below summarizes the results from four cores that tapped into the radioactive Marcellus formation. The depths at which the layer was found as well as the uranium measurements are presented.

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[15] Leventhal, 1981
[16] http://www.dec.ny.gov/energy/46288.html
[17] http://geology.com/articles/marcellus-shale.shtml
[18] CoPhysics 2010

Table 1. Uranium Content and Depth of Marcellus Shale in Four Cores

Location of the Core	Depth of Sample (feet)	Uranium Content (ppm)
Allegheny Cty, PA	7342 – 7465	8.9 – 67.7
Tomkins Cty, NY	1380 – 1420	25 – 53
Livingston Cty, NY	543 – 576	16.6 – 83.7
Knox Cty, OH	1027 – 1127	32.5 – 41.1

The four cores were taken from different geographical locations, but the characteristics of the identified Marcellus shale layer, specifically the high uranium and carbon content, are consistent. As mentioned earlier, DEC reports uranium content up to 100 ppm. The thickness of the Marcellus shale formation varies between 0 and 250 feet, according to isopach maps.

To compare the uranium content in parts per million (weight) to radioactive concentration in picocuries per gram, we use the correspondence[19]

2.97 ppm = 1 pCi/g U-238

Using this relationship, the U-238 ranges up to 28 pCi/g, or 33 times background for radium-226, assuming U-238 and Ra-226 are in secular equilibrium, as it is in Marcellus Shale formation. That is, the USGS measurements and the GAPI logs are consistent. The range of 6.6 to 30 pCi/g is our starting point for the concentrations of Ra-226 in the natural Marcellus Shale formation, to determine radon concentrations at the wellhead.

Numerical simulation shows the high concentrations of radon that will be found at the wellhead for Marcellus Shale gas, based on a variety of realistic assumptions. These assumptions include the rate at which radon is generated by radium-226 which, in turn, depends on the radium concentration in the shale. Otherwise there are no major uncertainties about the rate at which radon is produced. The radon's ability to escape from the rock matrix and be entrained by the natural gas flowing inward toward the well bore is less certain, but it can be estimated reasonably well. Our assumptions in the model we employed are listed in Table 2.

[19] See discussion in the Health Physics web site, http://www.hps.org/publicinformation/ate/q6747.html.

Table 2. Input Parameters For Model Simulation		
Parameter	***Value***	***Unit***
Depth of Horizontal Bore	5000	feet
Gas Temperature	105	° F
Well Bore r(min)	0.5	feet
Max gas-yielding radius r(max)	200	feet
Length of horizontal well bore	4000	feet
Gas Production Rate	10000	MCFD
Standard temperature for gas	59	° F
Standard pressure for gas	1	atm
Flowing pressures at r(min)	1500	psi
Flowing pressures at r(max)	2000	psi
Porosities at r(min)	10 - 50	%
Porosities at r(max)	4	%
Radium Activity	6.6 - 30	pCi/g
Rock Density	2.55	g/cm^3
Radon Emanation Factor	10 - 30	%

Numerical simulation thus shows – for typical flow rates, well dimensions, and other reasonable assumptions – that the concentration of radon in natural gas at the wellhead (expressed in pCi/liter) ranges between 36.9 to 2576 pCi/L. The two high values in Table 3, 1,858.6 pCi/L and 2576 pCi/L, are based on a radium concentration of 30 pCi/g. For the radon concentration 858.6 pCi/L, we assume a porosity of 30% and an emanation rate of 30%. The highest value assumes a porosity of 10% and an emanation rate of 30%.

All these are reasonable values and indicate the need for independent testing of production wells in the Marcellus shale formation. These radon concentrations in gas at the wellhead are far higher than the 40 pCi/liter wellhead concentration estimated by ATSDR or the 37 pCi/liter concentration that Raymond Johnson *et al.* considered average in pre-fracking days, though Johnson did find a maximum of 1450 pCi/L.

Transport from Wellhead to Household

Marcellus Shale gas and the accompanying radioactive gas, radon, is transported from the natural gas wellheads in Pennsylvania and New York to apartments and homes via pipelines. It is known that natural gas moves through pipelines at a speed of 10 to 12 miles per hour.

Because of the longer transit time from the Gulf Coast to New York City there is a lower concentration of radon than is the case with Marcellus Shale gas. The natural gas piped in from the Gulf Coast allows a radon decay up to two half-lives. This is equal to a reduction by 75% of the wellhead radon concentration.

The distance from Marcellus shale to New York City is much shorter; we are estimating this distance at the conservative figure of 400 miles. As shown in Table 3, the fraction of radon (Rn-222) remaining after transit is 76%.

Thus, over and above the effects of increased well concentrations of radon, the shorter transit time for Marcellus Shale gas will at least triple the risk compared to the risk that Raymond Johnson *et al* calculated for New York residents.

Radon Dilution in the Home and Potential Health Impacts

Given the radon concentration in natural gas arriving at the kitchen stove, the next issue is the dilution of radon within the apartment or home. This will allow us to determine the radon concentration within the home and the health impact to residents who use natural gas.

Johnson bases his dilution factor of 7111 on two values. First, he assumes the volume of a home, which he estimates at 8000 cubic feet (or 226.6 cubic meters). Secondly, he , figures the expected number of air exchanges as one per hour. An air exchange is the amount of time to replace the entire air volume of a dwelling.

We base our calculations on data from the US Environmental Protection Agency. On the basis of the EPA Factors Handbook[20], we take the volume of a dwelling as 183 cubic meters, rather than 226.6 cubic meters used by Johnson. This smaller volume is more representative of the size of an apartment in New York City.

For the number of air exchanges per hour, rather than one per hour, we take 0.71 air exchanges per hour. This is also more representative of New York City apartments[21]. With these changes, the dilution factor of 7111 is substantially modified. The factor of 7111 is multiplied by 0.57 and becomes 4053. This increases the radon concentration within a dwelling, as compared to Johnson's calculations.

To obtain the radon concentration within the home, we divide the radon concentration entering the home via a kitchen stove by the dilution factor of 4053, As seen in Table 3, the indoor concentrations range between 0.0187 pCi/L to 0.482 pCi/L.

Assuming a person resides in the home 70% of the time, we can determine the risk to a resident of developing lung cancer. The risk is based on a US Environmental Protection Agency analysis[22]. As seen in Table 3, the risk of developing cancer in a lifetime ranges from 1 in 10,000 to 1 in 391, an extremely high number. One then multiplies this risk by the number of persons who are potentially at risk.

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[20] Environmental Protection Agency, Exposure Factors Handbook, EPA/600/P-95/002Fa, August 1997.
[21] *Ibid*, p. 26-
[22] EPA, "EPA Assessment of Risks from Radon in Homes," EPA-402-R-03-003 (June 2003).

The number of persons potentially at risk in New York State can be roughly determined by the number of kitchen stoves fueled by natural gas in New York State multiplied by the number of persons in a household. According to the US Department of Energy[23], the number of households with natural gas fueled stoves in New York State is 4.4 million.

From the 2010 Census, the average number of persons per household in New York State is 2.69. Thus 11.9 million persons in New York State are potentially at risk. Multiplying the lifetime risk of inhaling radon gas by the number of persons in New York State at risk, we finally determine the potential number of lung cancers as ranging between 1183 to 30,484, out of a population at risk of 11.9 million. This is a major environmental impact and a public health impact that the New York Department of Environmental Conservation must carefully assess.

[23] DOE, Energy Information Administration, Table HC1.8

NY Baseline	Table 3. Approximate NY Range for Marcellus gas				
4.2	100	151	858.6	2576	pCi/l of radon in gas at wellhead
1500	400	500	400	400	miles from wellhead to customer
11	11	11	11	11	mr/hr typical speed of gas in pipeline
5.68	1.52	1.89	1.52	1.52	days transit time in pipeline
0.3576	0.76	0.7089	0.758528828	0.758528828	fraction of Rn-222 remaining after transit time
1.50192	75.85	107.0439	651.27	1953.97	pCi/l in natural gas delivered to customer
7111	4053	7111	4053	4053	Dilution factor
0.000211211	0.019	0.015053284	0.161	0.482	pCi/l lifetime exposure level in living space
1.23E-06	9.94E-05	8.75E-05	8.54E-04	2.56E-03	Lifetime risk (excess deaths per capita)
21	1183	1465	10160	30484	Excess deaths per 11.9 million residents
<1{.27)	17	20	145	435	Excess deaths per year per 11.9 million residents
Johnson, p. 14 for NYC distribution lines*	Numerical Similation Low-End values	Gogolak pp.5-26 Devonian shales*	Numerical Simulation High-End Values	Numerical Simulation High-End Values	**Basis for Radon Concentration**

*based on 16.76 million residents

porosity 10%, emanation 10%, radium 30 pCi/g

porosity 10%, emanation 30 %, radium 30 pCi/g

Mitigation of Impacts

Because radon is an inert gas radon cannot be chemically removed from the natural gas stream. But since radon has a 3.8 day half-life, the radioactive gas potentially could be stored for a sufficient period of time to allow the radon to decay to safe levels. In order to adequately protect residents of New York State, the material could be stored at wellhead locations for several months. If the gas was stored for two months, there would be a significant diminution of the hazard. Over this time period, the hazardous radioactive gas, radon, will decay by a factor 100,000.

From Gogolak, the estimated cost is on the order of $10 billion to develop sufficient pressurized storage in tanks. Some lag storage will be required in any case, since use of natural gas will not be uniform. The estimated costs for mitigating the environmental impact of radon is beyond the scope of this report.

Conclusion

The potential environmental and public health impact of radon in natural gas from the Marcellus Shale formation is enormous. This paper has calculated the number of lung cancers in New York State as ranging between 1,182 and 30,448. This calculation is based on reasonable assumptions for a gas well in the Marcellus Shale, including the concentration of radon at the wellheads, the transit time between wellheads and homes, the dilution expected in a typical household, and reasonable risk factors drawn from studies by the US Environmental Protection Agency.

In its 1400-page Draft Supplemental Environmental Impact Statement, the New York Department of Environmental Conservation has devoted one sentence to the issue of radon.. The sentence states "Radon gas, which under most circumstances is the main health concern from NORM [Normally Occurring Radioactive Materials], is produced by the decay of radium-226, which occurs in the uranium-238 decay chain."

Clearly, this one sentence does not constitute an adequate or thorough analysis of the potentially serious risks associated with the impacts of transporting radon-contaminated natural gas into the apartments and homes of New York State residents. The Draft Supplemental Environmental Impact Statement is obviously insufficient as written. It has completely ignored the problems associated with radon and the Marcellus Shale formation.

The Draft Supplemental Environmental Impact Statement must be withdrawn and it must be substantially revised so as to discuss the important environmental impacts and public health concerns of the radon problem. Until the radon risk has been appropriately studied and assessed, the Department of Environmental Conservation should not award any drilling permits in the Marcellus Shale formation in New York State. As a first and crucial step the DEC must make certain that radon at the wellheads from the Marcellus Shale formation in presently operating wells is measured. Tests must be conducted by independent experts and agencies. Such tests also must be scientifically rigorous in their design and be conducted with full transparency to assure public confidence in the validity of the testing.

There are strong economic interests supporting the development of Marcellus Shale gas. The potential for significant generation of jobs through the development of this resource is a real and important factor. Doubtless these economic factors will weigh on policy makers in Albany and potentially influence decisions regarding whether the Department of Environmental Conservation will move forward to adequately address the concerns raised in this paper.

The long-term environmental risks and public health concerns of radon in Marcellus Shale natural gas formations are far too serious to be ignored. The potential impacts of radon must not be swept under the rug. Nor should these impacts be sacrificed to short-term, economic policies or to unrealistic and/or inaccurate assessments of the benefits of natural gas development in New York State.

The long-term safety and health of New Yorkers is at stake, as is the health of New York State's extraordinary natural environment.

Climate Change

The Social Cost of Carbon

Estimating the Benefits of Reducing Greenhouse Gas Emissions

EPA and other federal agencies use the social cost of carbon (SCC) to estimate the climate benefits of rulemakings. The SCC is an estimate of the economic damages associated with a small increase in carbon dioxide (CO_2) emissions, conventionally one metric ton, in a given year. This dollar figure also represents the value of damages avoided for a small emission reduction (i.e. the benefit of a CO_2 reduction).

The SCC is meant to be a comprehensive estimate of climate change damages and includes changes in net agricultural productivity, human health, and property damages from increased flood risk. However, it does not include all important damages and, as noted by the IPCC Fourth Assessment Report [link], it is “very likely that [SCC] underestimates” the damages. The models used to develop SCC estimates, known as integrated assessment models, do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature because of a lack of precise information on the nature of damages and because the science incorporated into these models lags behind the most recent research. Nonetheless, the SCC is a useful measure to assess the benefits of CO_2 reductions.

The timing of the emission release (or reduction) is key to estimation of the SCC, which is based on a present value calculation. The integrated assessment models first estimate damages occurring after the emission release and into the future, often as far out as the year 2300. The models then discount the value of those damages over the entire time span back to present value to arrive at the SCC. For example, the SCC for the year 2020 represents the present value of climate change damages that occur between the years 2020 and 2300 (assuming 2300 is the final year of the model run). The SCC will vary by year for two reasons that work in opposite directions. In model runs with the last year fixed (e.g., 2300), the time spanning covered in the present value calculation will be smaller for later analysis years—the SCC in 2050 will include 40 fewer years of damages than the 2010 SCC. In addition, the SCC should increase over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change.

One of the most important factors influencing SCC estimates is the discount rate. A large portion of climate change damages are expected to occur many decades into the future and the present value of those damages (the value at present of damages that occur in the future) is highly dependent on the discount rate. To understand the effect that discount rate has on present value calculations, consider the following example. Let’s say that you have been promised that in 50 years you will receive $1 billion. In “present value” terms, that sum of money is worth $372 million today with a 2 percent discount rate. A higher discount rate of 3 percent would decrease the value today to $228 million and still the value would be even lower—$87 million with a 5 percent rate. This effect is even more pronounced when looking at the present value of damages further out in time. The value of $1 billion in 100 years is $138 million, $52 million, and $8 million, for discount rates of 2 percent, 3 percent, and 5 percent, respectively. Similarly, the selection of a 2 percent discount rate would result in higher SCC estimates than would the selection of 3 and 5 percent rates, all else equal.

EPA and other federal agencies have developed SCC estimates and used them to assess the benefits of rulemakings that reduce CO_2 emissions. EPA participated in an interagency working group that convened in 2009-2010 to design an SCC modeling exercise and select estimates for use in rulemakings. EPA estimated the SCC under a variety of assumptions determined by the interagency group using three integrated assessment models, which each combine climate processes, economic growth, and feedbacks between the two in a single modeling framework.

The interagency group selected four SCC values for use in regulatory analyses. The first three values are based on the average SCC from the three integrated assessment models, at discount rates of 5, 3, and 2.5 percent. SCCs at several discount rates are included because the literature shows that the SCC is highly sensitive to discount rate and because no consensus exists on the appropriate rate to use for analyses spanning multiple generations. The fourth value is the 95th percentile of the SCC from all three models at a 3 percent discount rate, intended to show the potential for higher-than-average damages. The table below summarizes the four SCC estimates in certain years. See the SCC Technical Support Document (PDF, 51pp, 854K) for a complete discussion about the methodology and resulting estimates.

Social Cost of CO_2, 2015-2050 [a] (in 2007 Dollars)

Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95th percentile
2015	$6	$24	$38	$73
2020	$7	$26	$42	$81
2025	$8	$30	$46	$90
2030	$10	$33	$50	$100
2035	$11	$36	$54	$110
2040	$13	$39	$58	$119
2045	$14	$42	$62	$128
2050	$16	$45	$65	$136

[a] The SCC values are dollar-year and emissions-year specific.

EPA first used these SCC estimates in the benefits analysis for the final joint EPA/Department of Transportation Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; see the rule’s preamble (PDF, 405 pp, 5.6MB) for discussion about application of the SCC (75 FR 25324; May 7, 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 Administration 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.

In light of these limitations, the U.S. government has committed to updating the current estimates as the science and economic understanding of climate change and its impacts on society improves over time. To help motivate and inform this process, Department of Energy and EPA have hosted a series of workshops. The first workshop focused on conceptual and methodological issues related to integrated assessment modeling and valuing climate change impacts, along with methods of incorporating these estimates into policy analysis. The second workshop reviewed research on estimating impacts and valuing damages on a sectoral basis.

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2.10.2 Direct Global Warming Potentials

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All GWPs depend on the AGWP for CO_2 (the denominator in the definition of the GWP). The AGWP of CO_2 again depends on the radiative efficiency for a small perturbation of CO_2 from the current level of about 380 ppm. The radiative efficiency per kilogram of CO_2 has been calculated using the same expression as for the CO_2 RF in Section 2.3.1, with an updated background CO_2 mixing ratio of 378 ppm. For a small perturbation from 378 ppm, the RF is 0.01413 W m^{-2} ppm^{-1} (8.7% lower than the TAR value). The CO_2 response function (see Table 2.14) is based on an updated version of the Bern carbon cycle model (Bern2.5CC; Joos et al. 2001), using a background CO_2 concentration of 378 ppm. The increased background concentration of CO_2 means that the airborne fraction of emitted CO_2 (Section 7.3) is enhanced, contributing to an increase in the AGWP for CO_2. The AGWP values for CO_2 for 20, 100, and 500 year time horizons are 2.47×10^{-14}, 8.69×10^{-14}, and 28.6×10^{-14} W m^{-2} yr (kg CO_2)$^{-1}$, respectively. The uncertainty in the AGWP for CO_2 is estimated to be ±15%, with equal contributions from the CO_2 response function and the RF calculation.

Updated radiative efficiencies for well-mixed greenhouse gases are given in Table 2.14. Since the TAR, radiative efficiencies have been reviewed by Montzka et al. (2003) and Velders et al. (2005). Gohar et al. (2004) and Forster et al. (2005) investigated HFC compounds, with up to 40% differences from earlier published results. Based on a variety of radiative transfer codes, they found that uncertainties could be reduced to around 12% with well-constrained experiments. The HFCs studied were HFC-23, HFC-32, HFC-134a and HFC-227ea. Hurley et al. (2005) studied the infrared spectrum and RF of perfluoromethane ($C\Omega F_4$) and derived a 30% higher GWP value than given in the TAR. The RF calculations for the GWPs for CH_4, N_2O and halogen-containing well-mixed greenhouse gases employ the simplified formulas given in Ramaswamy et al. (2001; see Table 6.2 of the TAR). Table 2.14 gives GWP values for time horizons of 20, 100 and 500 years. The species in Table 2.14 are those for which either significant concentrations or large trends in concentrations have been observed or a clear potential for future emissions has been identified. The uncertainties of these direct GWPs are taken to be ±35% for the 5 to 95% (90%) confidence range.

Table 2.14. Lifetimes, radiative efficiencies and direct (except for CH_4) GWPs relative to CO_2. For ozone-depleting substances and their replacements, data are taken from IPCC/TEAP (2005) unless otherwise indicated.

Errata

				Global Warming Potential for Given Time Horizon			
Industrial Designation or Common Name (years)	Chemical Formula	Lifetime (years)	Radiative Efficiency (W m^{-2} ppb^{-1})	SAR‡ (100-yr)	20-yr	100-yr	500-yr
Carbon dioxide	CO_2	*See below*[a]	*[b]$1.4x10^{-5}$*	*1*	*1*	*1*	*1*
Methane[c]	CH_4	*12*[c]	*$3.7x10^{-4}$*	*21*	*72*	*25*	*7.6*
Nitrous oxide	N_2O	*114*	*$3.03x10^{-3}$*	*310*	*289*	*298*	*153*
Substances controlled by the Montreal Protocol							
CFC-11	CCl_3F	*45*	*0.25*	*3,800*	*6,730*	*4,750*	*1,620*
CFC-12	CCl_2F_2	*100*	*0.32*	*8,100*	*11,000*	*10,900*	*5,200*
CFC-13	$CClF_3$	*640*	*0.25*		*10,800*	*14,400*	*16,400*
CFC-113	CCl_2FCClF_2	*85*	*0.3*	*4,800*	*6,540*	*6,130*	*2,700*
CFC-114	$CClF_2CClF_2$	*300*	*0.31*		*8,040*	*10,000*	*8,730*
CFC-115	$CClF_2CF_3$	*1,700*	*0.18*		*5,310*	*7,370*	*9,990*
Halon-1301	$CBrF_3$	*65*	*0.32*	*5,400*	*8,480*	*7,140*	*2,760*
Halon-1211	$CBrClF_2$	*16*	*0.3*		*4,750*	*1,890*	*575*
Halon-2402	$CBrF_2CBrF_2$	*20*	*0.33*		*3,680*	*1,640*	*503*
Carbon tetrachloride	CCl_4	*26*	*0.13*	*1,400*	*2,700*	*1,400*	*435*
Methyl bromide	CH_3Br	*0.7*	*0.01*		*17*	*5*	*1*
Methyl chloroform	CH_3CCl_3	*5*	*0.06*		*506*	*146*	*45*
HCFC-22	$CHClF_2$	*12*	*0.2*	*1,500*	*5,160*	*1,810*	*549*
HCFC-123	$CHCl_2CF_3$	*1.3*	*0.14*	*90*	*273*	*77*	*24*
HCFC-124	$CHClFCF_3$	*5.8*	*0.22*	*470*	*2,070*	*609*	*185*
HCFC-141b	CH_3CCl_2F	*9.3*	*0.14*		*2,250*	*725*	*220*

HCFC-142b	CH_3CClF_2	17.9	0.2	1,800	5,490	2,310	705
HCFC-225ca	$CHCl_2CF_2CF_3$	1.9	0.2		429	122	37
HCFC-225cb	$CHClFCF_2CClF_2$	5.8	0.32		2,030	595	181
Hydrofluorocarbons							
HFC-23	CHF_3	270	0.19	11,700	12,000	14,800	12,200
HFC-32	CH_2F_2	4.9	0.11	650	2,330	675	205
HFC-125	CHF_2CF_3	29	0.23	2,800	6,350	3,500	1,100
HFC-134a	CH_2FCF_3	14	0.16	1,300	3,830	1,430	435
HFC-143a	CH_3CF_3	52	0.13	3,800	5,890	4,470	1,590
HFC-152a	CH_3CHF_2	1.4	0.09	140	437	124	38
HFC-227ea	CF_3CHFCF_3	34.2	0.26	2,900	5,310	3,220	1,040
HFC-236fa	$CF_3CH_2CF_3$	240	0.28	6,300	8,100	9,810	7,660
HFC-245fa	$CHF_2CH_2CF_3$	7.6	0.28		3,380	1030	314
HFC-365mfc	$CH_3CF_2CH_2CF_3$	8.6	0.21		2,520	794	241
HFC-43-10mee	$CF_3CHFCHFCF_2CF_3$	15.9	0.4	1,300	4,140	1,640	500
Ferfluorinated compounds							
Sulphur hexafluoride	SF_6	3,200	0.52	23,900	16,300	22,800	32,600
Nitrogen trifluoride	NF_3	740	0.21		12,300	17,200	20,700
FFC-14	CF_4	50,000	0.10	6,500	5,210	7,390	11,200
FFC-116	C_2F_6	10,000	0.26	9,200	8,630	12,200	18,200

Table 2.14 (continued)

				Global Warming Potential for Given Time Horizon			
Industrial Designation or Common Name (years)	Chemical Formula	Lifetime (years)	Radiative Efficiency (W m–2 ppb–1)	SAR‡ (100-yr)	20-yr	100-yr	500-yr
Perfluorinated compounds (continued)							
FFC-218		2,600	0.26	7,000	6,310	8,830	12,500
FFC-318		3,200	0.32	8,700	7,310	10,300	14,700
FFC-3-1-10		2,600	0.33	7,000	6,330	8,860	12,500
FFC-4-1-12		4,100	0.41		6,510	9,160	13,300
FFC-5-1-14		3,200	0.49	7,400	6,600	9,300	13,300
FFC-9-1-18		>1,000d	0.56		>5,500	>7,500	>9,500
trifluoromethyl sulphur pentafluoride		800	0.57		13,200	17,700	21,200
Fluorinated ethers							
HFE-125		136	0.44		13,800	14,900	8,490
HFE-134		26	0.45		12,200	6,320	1,960
HFE-143a		4.3	0.27		2,630	756	230
HCFE-235da2		2.6	0.38		1,230	350	106
HFE-245cb2		5.1	0.32		2,440	708	215
HFE-245fa2		4.9	0.31		2,280	659	200
HFE-254cb2		2.6	0.28		1,260	359	109
HFE-347mcc3		5.2	0.34		1,980	575	175
HFE-347pcf2		7.1	0.25		1,900	580	175
HFE-356pcc3		0.33	0.93		386	110	33
HFE-449sl (HFE-7100)		3.8	0.31		1,040	297	90
HFE-569sf2 (HFE-7200)		0.77	0.3		207	59	18
HFE-43-10pccc124 (H-Galden 1040x)		6.3	1.37		6,320	1,870	569
HFE-236ca12 (HG-10)		12.1	0.66		8,000	2,800	860
HFE-338pcc13 (HG-01)		6.2	0.87		5,100	1,500	460
Perfluoropolyethers							
FFPMIE		800	0.65		7,620	10,300	12,400
Hydrocarbons and other compounds – Direct Effects							
Dimethylether		0.015	0.02		1	1	<<1
Methylene chloride		0.38	0.03		31	8.7	2.7

Methyl chloride	*1.0*	*0.01*	*45*	*13*	*4*

Notes:

[a] The CO_2 response function used in this report is based on the revised version of the Bern Carbon cycle model used in Chapter 10 of this report (Bern2.5CC; Joos et al. 2001) using a background CO_2 concentration value of 378 ppm. The decay of a pulse of CO_2 with time t is given by

$$a_0 + \sum_{i=1}^{3} a_i \cdot e^{-t/\tau_i}$$

Where $a_0 = 0.217$, $a_1 = 0.259$, $a_2 = 0.338$, $a_3 = 0.186$, $\tau_1 = 172.9$ years, $\tau_2 = 18.51$ years, and $\tau_3 = 1.186$ years.

[b] The radiative efficiency of CO_2 is calculated using the IPCC (1990) simplified expression as revised in the TAR, with an updated background concentration value of 378 ppm and a perturbation of +1 ppm (see Section 2.10.2).

[c] The perturbation lifetime for methane is 12 years as in the TAR (see also Section 7.4). The GWP for methane includes indirect effects from enhancements of ozone and stratospheric water vapour (see Section 2.10.3.1).

[d] Shine et al. (2005c), updated by the revised AGWP for CO_2. The assumed lifetime of 1,000 years is a lower limit.

[e] Hurley et al. (2005)

[f] Robson et al. (2006)

[g] Young et al. (2006)

tween euxinic and ferruginous conditions would have favored the early evolution and ecological expansion of a variety of anoxygenic photosynthetic metabolisms in pelagic environments. Expressions of biological oxygen production (such as those seen in the upper Mount McRae and Brockman BIF) would then have varied with the extent to which episodic or sustained pulses of reductants from the Earth's interior would have buffered photosynthetic oxygen, contributing to the protracted nature of Earth surface oxygenation during the Archean and Proterozoic (*26*).

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www.sciencemag.org/cgi/content/full/326/5953/713/DC1
Materials and Methods
Figs. S1 to S3
Table S1
References

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Improved Attribution of Climate Forcing to Emissions

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Evaluating multicomponent climate change mitigation strategies requires knowledge of the diverse direct and indirect effects of emissions. Methane, ozone, and aerosols are linked through atmospheric chemistry so that emissions of a single pollutant can affect several species. We calculated atmospheric composition changes, historical radiative forcing, and forcing per unit of emission due to aerosol and tropospheric ozone precursor emissions in a coupled composition-climate model. We found that gas-aerosol interactions substantially alter the relative importance of the various emissions. In particular, methane emissions have a larger impact than that used in current carbon-trading schemes or in the Kyoto Protocol. Thus, assessments of multigas mitigation policies, as well as any separate efforts to mitigate warming from short-lived pollutants, should include gas-aerosol interactions.

Multicomponent climate change mitigation strategies are likely to be much more cost effective than carbon dioxide (CO_2)–only strategies (*1*, *2*) but require quantification of the relative impact of different emissions that affect climate. Because globally and annually averaged radiative forcing (RF) is generally a good predictor of global mean surface temperature change, a scale related to RF is a logical choice for comparing emissions. The most widely used, and that adopted in the Kyoto Protocol, is the global warming potential (GWP), defined as the integrated global mean RF out to a chosen time of an emission pulse of 1 kg of a compound relative to that for 1 kg of CO_2. GWPs are thus based on radiative impact and atmospheric residence time and can include both the direct radiative effect of emitted species and radiative effects from indirect chemical responses. Previous studies, including the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4), provide estimates of RF and GWPs of short-lived gas emissions (*3*–*5*). However, except for the indirect effect of NO_x emissions on nitrate aerosol, gas-aerosol interactions were not included. These interactions occur primarily through ozone precursors altering the availability of oxidants, influencing aerosol formation rates, and through sulfate-nitrate competition for ammonium.

We used the composition-climate model Goddard Institute for Space Studies (GISS) Model for Physical Understanding of Composition-Climate Interactions and Impacts (G-PUCCINI) (*6*) to calculate the response to removal of all anthropogenic methane, carbon monoxide (CO) plus volatile organic compounds (VOCs), NO_x, SO_2, and ammonia emissions. This model couples gas-phase, sulfate (*7*), and nitrate (*8*) aerosol chemistry within the GISS ModelE general circulation model (GCM). Anthropogenic emissions are from a 2000 inventory (*9*). We calculated both the "abundance-based" RF owing to the net atmospheric composition response by species when all emissions are changed simultaneously and the "emissions-based" forcing attributable to the responses of all species to emissions of a single pollutant (Fig. 1). The sum of the forcings that take place via response of a particular species in the emissions-based analysis (each represented by a different color in Fig. 1) is approximately equal to the forcing due to that species in the abundance-based analysis. Likewise, the sums of all emissions-based and all abundance-based forcings are similar. Hence, the two viewpoints provide different but compatible pictures of how emissions and composition changes influence RF.

Emissions of NO_x, CO, and methane have substantial impacts on aerosols by altering the abundance of oxidants, especially hydroxyl, which convert SO_2 into sulfate. Global burdens of hydroxyl and sulfate change by 18% and 13% for increased NO_x, by –13% and –9% for CO, and by –26% and –11% for methane (sulfate forcing closely follows the sulfate burden change). Coupling in the other direction is very weak because reactions of gas-phase species upon aerosol surfaces have only a small effect on the global burden of the radiatively active species ozone and methane (e.g., anthropogenic SO_2 emissions enhance the removal of NO_x through reactions on particulate

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surfaces, causing ozone to decrease, but the RF is only –0.004 W/m^2). Increased SO_2 leads to substantially reduced nitrate aerosol, however, owing to greater ammonium sulfate formation at the expense of ammonium nitrate (*10*, *11*). We group CO and VOCs together for RF because they play similar roles in atmospheric chemistry, but the effects of historical CO emissions are ~3 to 7 times as great.

Methane emissions provide the second-largest contribution to historical warming after carbon dioxide. Including direct and indirect chemical effects and only the direct radiative effects of aerosols, NO_x emissions are the most powerful cooling agents (Fig. 1). However, adding in aerosol indirect effects (AIE) on clouds, which are highly uncertain (*12*), could make SO_2 emissions the stronger contributor to negative historical forcing. Atmospheric responses to individual species emissions changes are largely additive, with increases of 15% or less in the response of methane, ozone, sulfate, and hydroxyl when all pollutants are changed simultaneously, compared with the summed response to individual changes. Nitrate shows a greater discrepancy (~0.04 W/m^2), but the difference is well within uncertainty (0.10 W/m^2) (see Fig. 1 caption).

We present the results of several calculations of 100-year GWPs, the most commonly used time horizon, first reporting values without including indirect chemical responses of aerosols or CO_2 (as in the AR4, although the indirect responses of CO_2 are only 0.04 W/m^2 for CO and 0.02 W/m^2 for methane), then adding in the radiative effects resulting from the aerosol response to oxidant changes (Fig. 2). Reference CO_2 forcing is taken from the AR4, whereas the RF for all other gases and the direct radiative effects of aerosols are calculated within the GISS GCM for current conditions using the model's radiative transfer calculation and simulated composition response to 1-year pulse emissions. We also computed GWP, including a rough estimate of AIE, assuming they augment the sulfate aerosol direct radiative effects calculated here by 150%, taking the uncertainty range as 75 to 225% (*13*). Uncertainties in GWP are otherwise based on the RF uncertainties from AR4 (as in Fig. 1). We report GWPs for CO alone, because GWPs for different VOCs vary by an order of magnitude (*14*).

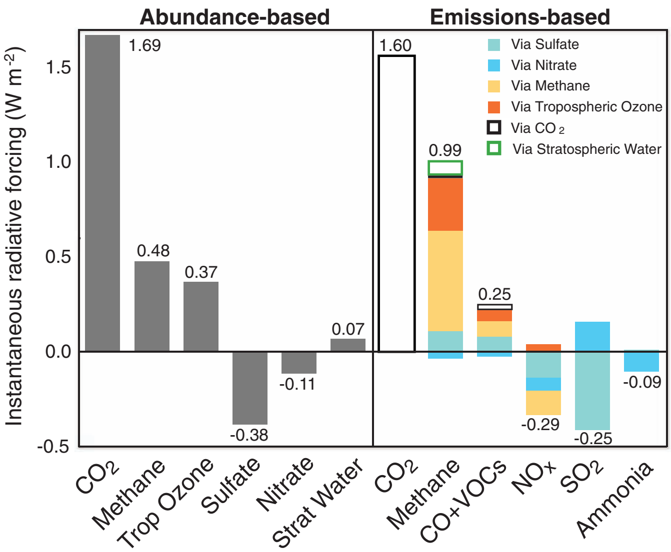

Fig. 1. Radiative forcing from 1750 to 2000. Numerical values within the figure give the net forcing (instantaneous at the tropopause). Uncertainties in the abundance-based values are 0.16 for CO_2, 0.05 for methane, +0.15 to –0.10 for ozone, 0.20 for sulfate, 0.10 for nitrate, and 0.05 for stratospheric water (*5*). For emissions-based values, we estimate uncertainties by adding the forcing uncertainties for each component in quadrature, yielding 0.14 for methane, 0.04 for CO+VOCs, 0.09 for NO_x, 0.23 for sulfate, and 0.10 for ammonia. AIE are not included. All forcing values are from this work except those from CO_2 and stratospheric water, which are based on the IPCC AR4 (*5*).

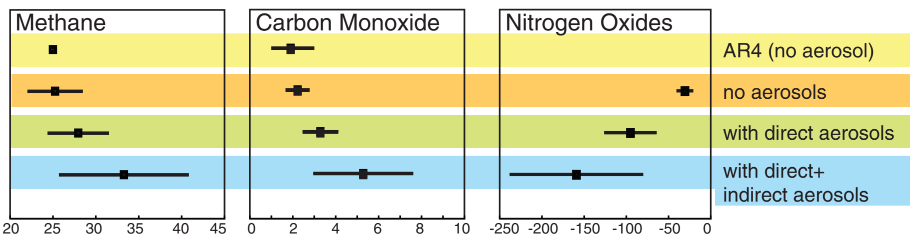

Fig. 2. The 100-year GWPs for methane, CO, and NO_x (per Tg N) as given in the AR4 and in this study when including no aerosol response, the direct radiative effect of aerosol responses, and the direct+indirect radiative effects of aerosol responses. The AR4 did not report uncertainties for methane or CO and gave no mean estimate for NO_x. The range for the GWP of CO is from the third IPCC assessment and encompasses values reported up through the AR4. Our calculations for the shorter 20-year GWP, including aerosol responses, yield values of 79 and 105 for methane, 11 and 19 for CO, and –335 and –560 for NO_x, including direct and direct+indirect radiative effects of aerosols in each case. The 100-yr GWPs for SO_2 (per Tg SO_2) and ammonia would be –22 and –19, respectively, including direct aerosol radiative effects only, and –76 and –15 adding indirect aerosol radiative effects. GWPs for very short-lived NO_x, SO_2, and ammonia will vary widely by emission location and timing, and hence global values are of limited use.

Our value for the 100-year GWP of methane when including only the responses of methane, ozone, and stratospheric water vapor is almost identical to the comparable AR4 value. The GWP is substantially larger when the direct radiative effects of the aerosol responses are included, however. It becomes larger still, including aerosol-cloud interactions, although uncertainties increase as well. Although results are not statistically different at the 95% confidence level, the best estimate is nonetheless substantially larger when gas-aerosol interactions are included. The 100-yr GWP for CO was 1.9 in AR4, with a 1.0 to 3.0 range based on the third IPCC assessment and subsequent results (*3*, *14*). As with methane, our GWP is similar to those in previous work when aerosol responses are neglected but is substantially larger when these responses are included. GWPs become extremely difficult to define for shorter-lived species because they depend strongly on the location and time (season and day) of the emission pulse (*15*). Estimates of 100-year GWPs for global surface NO_x emissions report values of roughly –10 to –30, including the indirect responses of methane and ozone only (*16*, *17*), in very rough accord with our results, but differences in the imposed emissions changes preclude a rigorous comparison.

Although our calculations are more complete than previous studies, additional processes should be included as they become better understood. These include mixing between aerosol types (*18*), formation of secondary organic aerosols, which are sensitive to both organic aerosol emissions and oxidant levels (*19*), and interactions between pollutants and ecosystems. The latter includes suppression of CO_2 uptake by increased surface ozone concentrations (*20*), aerosols enhancing the ratio of diffuse to direct radiation reaching the biosphere leading to increased CO_2 uptake (*21*) (at least for some plant types when aerosol loading is not so large as to dramatically reduce total surface irradiance), and the effects of nitrogen and sulfur deposition on ecosystems. These effects may be important but are highly uncertain at present. Ecosystem-chemistry interactions add both positive and negative forcing terms to the GWP of NO_x (NO_x leads to increased ozone, causing increased CO_2, but also leads to increased aerosol, causing decreased CO_2), adding to an already complex set of multiple, sometimes opposing, forcings (Fig. 1). For CO and methane, however, increased emissions lead to increased CO_2 from both the ozone-ecosystem interactions and the aerosol-ecosystem interactions, so would simply increase their positive GWPs still further.

Hence, the uncertainty in quantifying these processes implies only that the larger estimates of CO and methane GWPs presented here may still be too low.

Although we focus on global mean results, the effects of oxidant changes on sulfate are stronger in areas with high SO_2 emissions that are more oxidant-limited. This is in accord with previous results showing a strong sulfate response over high-emission regions in Asia to perturbations in North American emissions attributable to NO_x emissions changes followed by long-range ozone transport (*22*). The global sulfate response to oxidant changes can be large, because much of the industrialized Northern Hemisphere is oxidant-limited, especially during winter (*23*), but the oxidant-aerosol interactions may show greater sensitivity to emission trends in peak emission regions. Consistent with this, the ratio of the sulfate to hydroxyl burden changes is greater in response to NO_x and CO emissions, generally colocated with SO_2 emissions, than for methane. Our previous results showed a small global mean net impact of all ozone precursors on sulfate forcing despite large regional forcings (*24*). Although that study used different emissions (a future scenario), those results seem reasonably consistent because the sum of the sulfate responses to all historical ozone precursors in this work is only 0.06 W/m^2.

Our results indicate that NO_x emissions cause a substantial net cooling at all time scales. In contrast, CO emissions cause warming. The 100-year GWP for methane is ~10% greater (~20 to 40%, including AIE) than earlier estimates (*5*) that neglected interactions between oxidants and aerosols. GWPs for methane and CO would likely be further increased by including ecosystem responses. Decreased emissions of SO_2 warm climate, but including the sulfate-nitrate interaction makes the climate impact less severe than might otherwise have been thought.

There are many limitations to the GWP concept (*25*). It includes only physical properties, and its definition is equivalent to an unrealistic economic scenario of no discounting through the selected time horizon followed by discounting to zero value thereafter. The 100-year time horizon conventionally chosen strongly reduces the influence of species that are short-lived relative to CO_2. Additionally, GWPs assume that integrated global mean RF is a useful indicator of climate change. Although this is generally reasonable at the global scale, GWP does not take into account the rate of change, and it neglects that the surface temperature response to regionally distributed forcings depends on the location of the RF (*26*) and that precipitation and circulation responses may be even more sensitive to RF location (*27*). Along with their dependence on emission timing and location, this makes GWPs particularly ill-suited to very short-lived species such as NO_x, SO_2, or ammonia, although they are more reasonable for longer-lived CO. Inclusion of short-lived species in agreements alongside long-lived greenhouse gases is thus problematic (*28*, *29*). Hence, emissions of short-lived species have traditionally been, and will likely continue to be, primarily regulated by local- to regional-scale policies targeting air quality. Should policies aim to mitigate climate change by separately targeting short-lived species emissions, however, they should consider effects across gas-phase and aerosol species. Furthermore, assessment of policies affecting particular sectors that emit both long- and short-lived species should include the overall impact rather than simply the impact of long-lived gases.

Despite their limitations, GWPs are widely used for comparison among long-lived gases, forming the basis for worldwide political agreements on climate and carbon trading. Because the latter was a $126 billion/year market in 2008 (*30*), even small differences in GWPs can have large economic consequences. Our results suggest that gas-aerosol interactions play an important role in methane's GWP, and hence our larger value would allow better optimization of climate change mitigation policies. Methane's GWP may also change with time as air quality regulations alter the background state of tropospheric chemistry. Finally, our results demonstrate that improving our knowledge of aerosol-climate interactions is important not only for better understanding the aerosol contribution to past and future climate change, but even for correctly evaluating the effects of long-lived greenhouse gas emissions from methane-oxidant-aerosol interactions.

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Control of Iron Homeostasis by an Iron-Regulated Ubiquitin Ligase

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Eukaryotic cells require iron for survival and have developed regulatory mechanisms for maintaining appropriate intracellular iron concentrations. The degradation of iron regulatory protein 2 (IRP2) in iron-replete cells is a key event in this pathway, but the E3 ubiquitin ligase responsible for its proteolysis has remained elusive. We found that a SKP1-CUL1-FBXL5 ubiquitin ligase protein complex associates with and promotes the iron-dependent ubiquitination and degradation of IRP2. The F-box substrate adaptor protein FBXL5 was degraded upon iron and oxygen depletion in a process that required an iron-binding hemerythrin-like domain in its N terminus. Thus, iron homeostasis is regulated by a proteolytic pathway that couples IRP2 degradation to intracellular iron levels through the stability and activity of FBXL5.

Iron regulatory proteins 1 and 2 (IRP1 and IRP2) function as RNA-binding proteins during iron-limiting conditions in order to regulate the translation and stability of mRNAs encoding proteins required for iron homeostasis (*1*, *2*). In iron-replete cells, IRP RNA binding is reduced because of the assembly of a 4Fe-4S cluster in IRP1 (*3*) and the proteasomal degradation of IRP2 (*4*–*7*). Despite the importance of IRP2 in iron metabolism, the ubiquitin ligase